INDONESIAN PETROLEUM PRODUCTION SHARING CONTRACTS: EMPIRICAL EVIDENCE, COMMERCIAL PERFORMANCE AND EXTENDED RISK ANALYSIS

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ABSTRACT

Since the introduction of the petroleum Production Sharing Contract (PSC) system by the Indonesian government in the 1960s, this system has been considered a model for other petroleum-producing nations to emulate. Unfortunately, with the continual decline in performance displayed by this partnership, its capability as an attractive partnership system has been questioned. This thesis proposes three main factors contributing towards the dismal performance of the Indonesian PSC arrangement: the commercial viability of the petroleum Exploration & Production (E&P) industry, the PSC as a system and the negative perception of the investment climate in Indonesia itself. Employing the cash flow analysis and the risk analyses using the Monte Carlo simulation technique and Analytic Hierarchy Process (AHP) in the Benefit-Cost-Risk framework, the research concludes that the commercial capability and productivity of the Indonesian PSC have declined in recent years. The Monte Carlo simulation shows that the tax consolidation approach proposed for the frontier areas has not contributed effectively in consolidating the production partnership system, whilst enhancement of several PSC variables as incentives are required and should be offered based on its production rate profile. The result of AHP analysis points to the need to consider the application of the Modern Royalty and Tax system as an alternative to the PSC system. This study strongly suggests the role of foreign direct investment climate in Indonesia as the critical factor in improving the Indonesian PSC system as an attractive mode in managing Indonesia's growing petroleum E&P industry.

ABSTRAK

Sejak pelaksanaan sistem Perkongsian Kontrak Pengeluaran (PSC) petroleum oleh kerajaan Indonesia dalam tahun 1960an, ia telah dianggap sebagai suatu model perkongsian pengeluaran minyak yang wajar dicontohi oleh negara-negara pengeluar minyak lain. Namun, sejak kebelakangan ini dengan kemerosotan yang berterusan yang dialami dalam pencapaian sistem perkongsian ini, telah timbul keraguan terhadap kemampuannya untuk terus bertahan sebagai satu sistem perkongsian yang menarik. Kajian ini telah mencadangkan tiga punca utama yang membawa kepada kemerosotan dalam sistem perkongsian ini: daya maju komersial industri carigali dan pengeluaran petroleum (E&P), PSC sebagai satu sistem dan persepsi negatif terhadap suasana pelaburan asing di Indonesia. Melalui analisis aliran tunai dan analisis risiko mengguna teknik simulasi Monte Carlo dan analisis Proses Hirarki Analitik (AHP) dalam kerangka faedah-kos-risiko, kajian ini merumuskan bahawa kemampuan komersial dan produktiviti PSC Indonesia telah merosot beberapa tahun terakhir ini. Analisis Monte Carlo menunjukkan bahawa cadangan untuk memperketatkan usaha pencukaian untuk kawasan yang belum diteroka tidak dapat membantu memperkukuhkan sistem perkongsian pengeluaran, sedangkan pembaikan beberapa pembolehubah PSC saiz sebagai insentif diperlukan dan sewajarnya diberikan berdasarkan profil pengeluaran. Analisis AHP merumuskan bahawa pendekatan Sistem Royalti dan Cukai Baru (RAT) perlu dipertimbangkan untuk menggantikan sistem PSC. Kajian ini mencadangkan peranan iklim pelaburan asing langsung di Indonesia sebagai faktor utama bagi memperbaiki sistem PSC sebagai pendekatan yang baik bagi mengurus industri carigali petroleum yang semakin berkembang di Indonesia.

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

LIST OF ABBREVIATION

AFTA	:	ASEAN Free Trade Area
AHP	:	Analytic Hierarchy Process
APBN	:	Anggaran Pendapatan dan Belanja Negara (Annual State Budget)
APEC	:	Asia-Pacific Economic Cooperation
ARCO	:	Atlantic Richfield Company
ASEAN	:	Association of Southeast Asian Nations
BKKA	:	Badan Koordinasi Kontraktor Asing
BOEPD	:	Barrel Oil Equivalent per day
BOPD	:	Barrel Oil per day
BP MIGAS	:	Badan Pelaksana Kegiatan Usaha Hulu Minyak dan Gas Bumi (Executive Agency for Upstream Oil & Gas Business Activities)
BPKP	:	Badan Pengawas Keuangan Pembangunan (Controller of the Development Funds)
BPPKA	:	Badan Pembinaan Pengusahaan Kontraktor Asing (Foreign Contractors Management Body)
CALTEX	:	California Asiatic Oil Company in a joint venture with Texaco Overseas Petroleum Company
Capex	:	Capital Expenditures
CDF	:	Cumulative Distribution Function
CEO	:	Chief Executive Officer

CET	: Contractor Entitlement
Con	: Contractor
CoR	: Contract Risk
COW	: Contract of Work
CosRec	: Cost Recovery
CP	: Current Production
CPOS	: Contractor profit oil share
cpss	: Contractor Production Sharing Split
CR	: Cost Risk
CSFTP	: Contractor FTP share
CTI	: Contractor Taxable Income
DDBL	: Double Declining Balance
DKKA	: Dinas Koordinasi Kontraktor Asing
DMO	: Domestic Market Obligation
DMO-hol	: Domestic Market Obligation holiday price
dmorate	: DMO rate
dmoprice	: DMO price
DPR	: Dewan Perwakilan Rakyat (Indonesian Parliament)
E&P	: Exploration and Production
EOR	: Enhanced Oil Recovery
EUR	: Estimated Undiscovered Reserves
ESCAP	: Economic and Social Commission for Asia and the Pacific
Exp	: Expenditure
FR	: Fiscal Risk
FTP	: First Tranche Petroleum
ftprate	: First Tranche Petroleum rate

GOI	:	Government of Indonesia
GOIPOS	:	GOI profit oil share
GOISFTP	:	GOI FTP share
GOITk	:	GOI Take
GR	:	Geological Risk
GRev	:	Gross Revenues
GSR	:	Geology Success Factor
IC	:	Investment Credit
icrate	:	Investment Credit rate
IIAPCO	:	Independent Indonesian American Petroleum Company
IMF	:	International Monetary Fund
IP	:	Incentive Package
IP1	:	First Incentive Package
IP2	:	Second Incentive Package
IP3	:	Third Incentive Package
IP4	:	Fourth Incentive Package
IP5	:	Fifth Incentive Package
IPA	:	Indonesian Petroleum Association
IRR	:	Internal Rate of Return
IRS		Internal Ruling Service
JOA	:	Joint Operation Agreement
JOB	:	Joint Operation Body
JOC	:	Joint Operating Committee
LNG	:	Liquid Natural Gas
MBOPD	:	Thousand Barrel oil per day
MIGAS	:	Direktorat Jendral Mninyak dan Gas Bumi

		(The Directorate General for Oil and Gas, subdivision of the Ministry of Mines and Energy)
MMBBL	:	Million of Barrels
MMBO	:	Million Barrels Oil
MMBOD	:	Million Barrels Oil per Day
MMBOED	:	Million Barrels Oil Equivalent per Day
MMCFT	:	Million Cubic Feet
MMSTB	:	Million Stock Tank Barrels
NPV	:	Net Present Value
NR	:	Net Revenues
Nopex	:	Non Capital expenditures
NR	:	Net Revenues
OPEC	:	Organization of Petroleum Exporting Countries
P	:	Production
PDF	:	Probability Distribution Frequency
Permigan	:	Perusahaan Negara Pertambangan Minyak dan Gas Nasional
Permina	:	Perusahaan Negara Pertambangan Minyak Nasional
Pertamin	:	Perusahaan Negara Pertambangan Minyak Indonesia
PERTAMINA		Perusahaan Negara Pertambangan Minyak Indonesia (Indonesian Petroleum and Gas Mining Company)
PoR	:	Political Risk
POT	:	Pay Out Time
PO	:	Profit Oil
PR	:	Price Risk
Prc	:	Average Price annually
PSC	:	Production Sharing Contract

R	:	Reserves
RAT	:	Royalty and Tax
RDR	:	Remaining Discovered Reserves
RORC		Rate of Return Contract
R/P	:	Reserve to Production Ratio (Reserve/Production)
RSC	:	Risk Service Contract
SC	:	Service Contract
SHELL	:	N.V. De Bataafsche Petroleum Maatschappij or Royal Dutch Shell
STANVAC	:	Standard Oil Company of New Jersey in joint venture with Mobil
TAC	:	Technical Assistance Contract
TCF	:	Trillion Cubic Feet
TCsh	:	Total Contractor Share
TGOITk	:	Total GOI Take
TRA	:	Total Reserve Addition
TSCF	:	Trillion Standard Cubic Feet
UN	:	United Nation
US		United Stated of America
USA	:	United Stated of America
USD	:	United Stated Dollar
VAT	:	Value Added Tax
WP	:	Work Program
WTO	:	World Trade Organization

LIST OF APPENDICES

CHAPTER 1

INTRODUCTION

Mankind has known petroleum, which has come to the surface of the earth through natural forces, for thousands of years. In 1859 Colonel Drake drilled the first well in Titusville Pennsylvania USA for the specific purpose of bringing liquid petroleum to the surface (Pertamina, 1994:3). The discovery touched off an oil boom. Hundreds of wells were drilled in Pennsylvania, followed by discoveries in other states and countries, including Indonesia.

In many petroleum-producing countries, petroleum has dominated the country's economy. Countries with petroleum resources have been very careful in managing their wealth. However, the outcome of upstream oil and gas exploration and production (E&P) activity has considerable uncertainties and risks, including technical (geological and technology) as well as economic (cost, market and price) and country (contractual, fiscal and political) risks respectively. In addition to requiring large capital outlay and technology, the upstream petroleum activity is also characterised by long lead times for exploration, development and production. Therefore, this venture needs higher risk premium compared to other business and the decision to invest in oil and gas venture must be taken in full consideration, taking into account the above risks and uncertainties.

The financial burden and high risks of venturing in petroleum E&P business appear to be just too large to be shouldered alone by a developing country that has many other priorities. Therefore developing countries have invited oil companies to share the risks by providing the risk capital for petroleum E&P in exchange of direct shares of potential profit governed under types of petroleum contractual arrangement.

There are two parties in common petroleum contract; they are the government (in some cases delegated to national oil company or government agency) as the first party and private petroleum company as the second party. The petroleum company objectives are to build equity and to maximise wealth by finding and producing reserves at the lowest possible costs and at the highest possible profit margin in the shortest possible time. On the other hand the objectives of the host government entering into petroleum contract are to optimise the wealth from its natural resources, to maintain an optimal level of exploration for sustaining the growing of the industry and to minimise administrative costs through improvement in efficiency. In this case it is important to emphasize the word to optimise rather than to maximise. Higher government's revenues can be achieved by lower contractor production sharing split and higher taxes, but such judgment may result in decreasing level of activity and investment. Therefore the government's revenues will not be optimised; any system must provide an appropriate balance (Marcotte, 2001:1-2).

Moreover in most cases there are significant differences in the abilities of the parties to bear the risks involved. These are the reasons why petroleum contracts are potentially unstable and the parties may want to renegotiate at some point in time. In some cases, although in general the projects are economically attractive, the projects probably may not be developed. Uncertainties over risk and reward sharing prevent one or both parties to continue with the venture.

Johnston (1994:21-27) categorised petroleum contracts into three main types of contract arrangements; they are Concessionary or Royalty and Tax (RAT), Production Sharing Contract (PSC) and Risk Service Contract (RSC). The basic difference between them is their attitude towards the ownership of the petroleum resources. In concessionary system the ownership of petroleum resources is transferred to the petroleum company, while in the other two systems the host government retains ownership of petroleum resources.

In Concessionary or RAT system the petroleum resources may be privately owned through government licensing. The host government only sets up the rules for licensing, such as establishing a fee for land use and degradation, imposing royalty and production taxes without being involved with the operation of the industry itself. Hence all risks are borne by the petroleum company at any phases of the operation. The host government main revenues come from royalties before production and taxes after production. Therefore this system is also called Royalty and Tax system (RAT).

In RSC system, the host government still keep the ownership of resources; the petroleum company serves as a contractor, to explore at its sole risk. In the case of no commercial discovery, the contractor does not get fee; while in the case of commercial discovery, it develops and produces the resource. The contractor covers its expenditures for exploration, development and production. As payment for their services the contractor gets fee in cash.

The PSC system was introduced in the mid 1960's by Indonesia, as a reflection of Indonesian nationalism following its declaration of independence in 1945. Article 33 of the 1945 Indonesian Constitution states that branches of production important to the state and which affect the life of most people shall be under the jurisdiction of the state and that the land and water and natural riches contained therein shall be under the jurisdiction of the State and utilised for the greatest welfare of the people.

The concept was adopted from the sharing of the harvest between landowner and tenant. The keys of the PSC system are the state ownership and the sharing of production. The petroleum company serves as a contractor, to explore at its sole risk. The contractor will recover its expenditures for E&P activities only from the petroleum produced in the case of commercial discovery. The remainder of production, named the profit oil, is shared between the host country and the contractor, and can be regarded as payment or compensation for the risks taken and the service provided. The contractor has to pay income tax on its share of profit. If no oil or gas is found the petroleum company receives no compensation.

Although the rules of PSC can be interpreted as being strict by some investors, the concept provides foreign investor with an attractive opportunity for profitable operation; thereby it has been used as a model in various countries throughout the world. The data set of empirical economic analysis of the PSC system that had done by Bindemann's (1999:47) showed that during 1966 to 1998 period there were 268 PSCs signed by 74 countries around the world.

1.1. Background Issues

In 21st century oil and gas is still important as vital energy. The requirement of oil and gas will continue as long as there is no other viable alternative. The countries which posses these resources understand their preciouses reserves, and wish to maximise their wealth by actively participating in their development.

In the era of intense global competition in the 21st century, the market for E&P capital and technology is extremely competitive and sophisticated. The competing variables include geological potential; contract system, terms and variables; costs; risks; investment climate and others. Many countries are re-evaluating their competitive position. Therefore more lenient terms for fields in remote, high cost areas and marginal fields are expected.

Moreover, the recent trend of mergers, consolidation and acquisitions within the oil and gas industry place the exploration budget in fewer hand, thereby the number of players seeking for exploration rights is likely to lessen (Hasan, 2001:11). Through acquisitions, a petroleum company may get good new work areas not only with lower capital investments, but also with lower risks and shorter lead-times.

To summarise, the need for petroleum risk capital investment continues and increases, especially in developing countries, and these countries realise that they have to compete for scarce fund. As Machmud said:

> "Willingness to put real money at risk in the midst of risk capital scarcity can no longer be taken for granted and must be made attractive, therefore, also needs to be balanced over time, since a deal

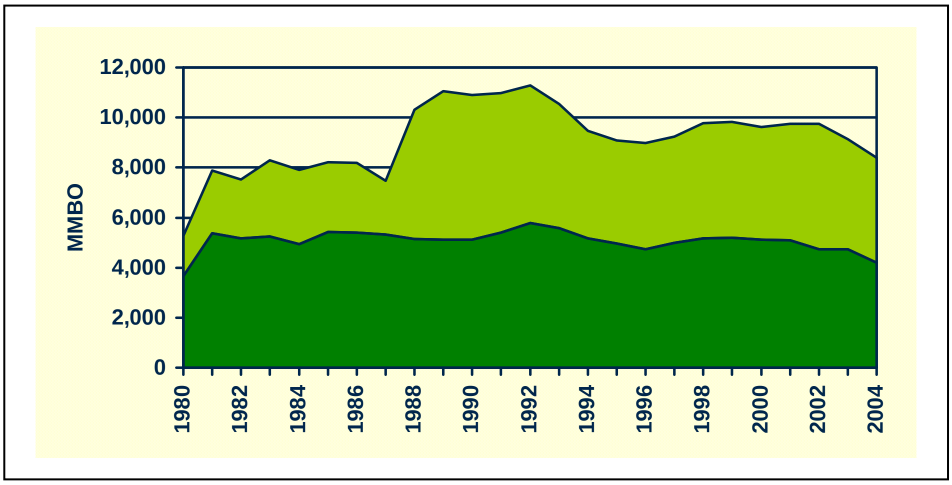
that balanced to day can easily become unbalanced in the future"

(Machmud, 2000:1)

Therefore the oil producing countries shall continue to offer attractive contract terms that balancing between risk and reward.

Indonesia is no exception; like many petroleum producing countries Indonesia's petroleum revenues have dominated the country's economy. Oil and gas are critical resources which fuel the development of Indonesia's economy and their importance will continue into the 21st century. The large deposits of oil and gas resources would provide a huge potential in support of the development aspirations of the country.

Figure 1.1 shows total Indonesia's oil reserves as of January 2004 were reported to be approximately 9,131 million barrels oil (MMBO), in which 4,7278 MMBO were proven and 4,403 MMBO were potential (BP Migas, 2004). Although showing a declining tendency in production rate from 1.25 million barrels oil per day (MMBOPD) in 2002 to 1.01 MMBOPD in 2003 (approximately 1.8% of the world's production), Indonesia ranked seventeenth among world oil producers (US Embassy, 2004:1).



Note: Dark green: proven and Light green: potential

Figure 1.1: Indonesia's Oil Reserves 1980 – 2004 (BP Migas, 2004)

Moreover Indonesia also ranked sixth among the world gas producers (US

Embassy, 2004:1). Figure 1.2 shows Indonesia had bountiful natural gas reserves of over 178 trillion cubic feet (TCF), in which 91 TCF were proven and 87 TCF potential (BP Migas, 2004). On contrary to oil production, there was an increasing tendency on the gas production, from 3.04 TCF of gas in 2002 to around 3.06 TCF in 2003. Indonesia also remains the world's largest exporter of liquefied natural gas (LNG) in 2002 at 26.2 million metric tons. Although it enjoyed as 22.9% world market share, this dominance was under threat from newer producers in Qatar, Australia and Russia (US Embassy, 2004:1).

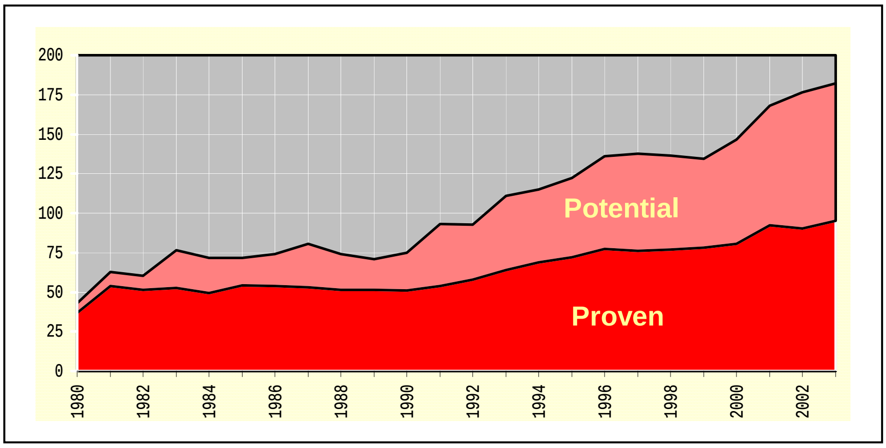


Figure 1.2: Indonesia's Gas Reserves 1980 – 2003 (BP Migas, 2004)

The result of survey by PriceWaterhouseCooper (2002:5-9) in 2002 involving the CEOs of petroleum E&P companies operating in Indonesia showed that Indonesia's geological potential had been the most attractive feature supporting foreign investment; Indonesia remained attractive, in terms of petroleum geological potential. Moreover, cross-comparison of geological potential among some South East Asia countries concluded that Indonesia was categorised as one of the top three countries with geological potential of oil and gas in South East Asia (Usman, 2000: 18 – 29). The ranking parameters included current production, reserves size, total reserve addition; remaining discovered reserves; reserve/production ratio; finding rate including geological success ratio, reserves addition per well, drilling density; size of discoveries and licensing activity. A similar result was also obtained in analysing the oil and gas potential by the use of Analytic Hierarchy Process (AHP) method. AHP result showed that geological potential of natural gas in Indonesia was still the highest among the South East Asia countries, while for oil Indonesia was more attractive than Malaysia and Vietnam, although it had assumed a decreasing of finding rate by 10% (Usman, Irjianto and Kasmungin, 2003: 45 - 54).

Figure 1.3 shows the map of Indonesia oil and gas resources, which are buried underneath sixty tertiary sedimentary basins, covering an area of more than two millions square kilometres. However, only 25% of the area or 15 basins are producing, largely are located in the western-part of Indonesia. The remaining 75% or 45 basins have either been proven to contain hydrocarbon but have not been produced, drilled but no discoveries have been made, or have not been drilled at all. They are mostly located in the eastern-part of Indonesia, in deep water or in remote areas known as frontier areas. Note that approximately 30% of the offshore basins in the western part and 80% of the basins in the eastern part of Indonesia are classified as deep-sea basin. These facts indicate that in order to increase its petroleum reserves, raising the exploration investment level particularly in deep water and frontier areas in the eastern part of Indonesia is needed.

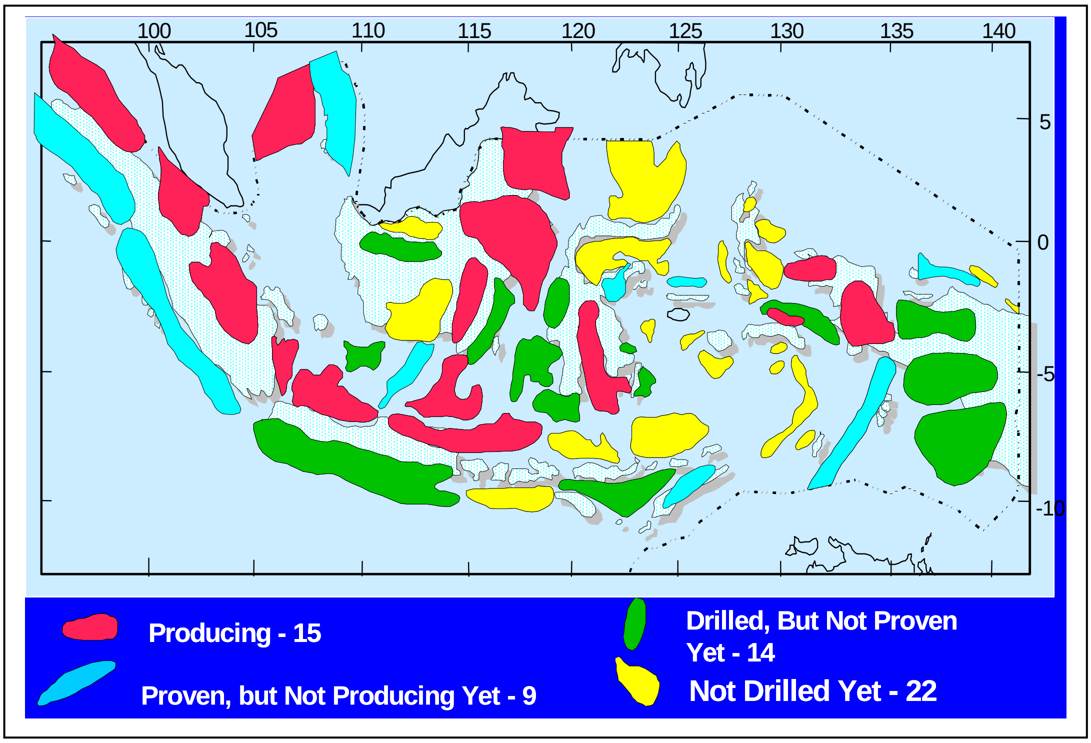


Figure 1.3: The Indonesia's Hydrocarbon Basins (Sudibyo, 2004; and BP Migas, 2004)

Similar to other developing countries, Indonesia has invited petroleum companies to share the risks by providing the risk capital for petroleum E&P investment in exchange of direct shares of potential profit under some types of contractual arrangement. Through the years the agreement under which petroleum companies operate in Indonesia has changed considerably.

Up to 1963, Indonesia's petroleum industry was operated under the RAT system. In 1960, The Petroleum Law No. 44 Prp of 1960, which was based on the government's exclusive right to exploit oil resources, was introduced. The law consisted of enlisting the services of private foreign companies to conduct oil operations as a contractor to the national petroleum companies. As a result, three foreign oil companies holding oil concessions at that time surrendered their concessions and signed a contract of work (COW) with three national petroleum companies existed in 1963 (Pertamin, Permina and Permigan). It was an important step taken towards direct participation in exploration and development of Indonesia's natural resources. To effectively use manpower and capital, in 1969 these three national petroleum companies were merged into single entity, Pertamina.

A new momentum was given to the Indonesia's petroleum industry when the first PSC contract was signed between IIAPCO and Permina, covering a block in the western part of offshore Java Sea on August 1966. After that the PSC system and its variant were the only contract's system applied in Indonesia.

Indonesian PSC system was based on two legal frameworks. The first one was the Article 33 of the 1945 Indonesian Constitution, which stated that the land and water and natural riches contained therein shall be under the jurisdiction of the state and utilized for the greatest welfare of the people. The second one was Foreign Investment Law Number 1 of 1967, which states that the term of foreign capital investment pursuant to Article 1 of the Law 1/1967 refers to direct foreign investment, in which the capital owner will bear the risk from such investment.

Some main variables of the Indonesian PSC system are the first tranche petroleum, investment credit, cost recovery, depreciation method to recover the capital expenditures as well as contractor production sharing split, domestic market obligation (DMO), price of the DMO, length of DMO price holiday and the tax rate respectively. These variables will be discussed thoroughly in Chapter 2.

Petroleum contracts are designed to govern a long-term relationship, negotiated on the basis of existing conditions and assumed factors that will not confirmed for many years to come. Therefore, when the conditions and assumed factors changed, pressure for changing unsatisfactory terms of the contract could not be avoided. Indonesia case is no exception; over the time the financial terms have changed. For example, over the years Indonesia has made several revisions or amendments in the original PSC contract. The first revision was made following the drastic increased in crude oil prices in 1973, increasing the production sharing split to 85/15 for oil and 70/30 for gas in favour of GOI. Subsequent revisions involved providing additional economic incentives to meet the industry's plight for improved terms. As a result, there have been three generations and five economic incentives packages investment in the development of the Indonesian PSC; they were PSC first generation (PSC1) to third generation (PSC3) and incentives package 1 (IP1) to incentives package 5 (IP5). Terms, variables and conditions of each Indonesia’s PSC type and incentive package are discussed in Chapter 2.

Since 1966 the PSC system has dominated the petroleum contracts signed in Indonesia. Up to the end of 2003, a total of 347 petroleum contracts had been signed. Out of all those contracts, 257 contracts or 74% were PSC contracts, in which 105 were still active. Out of the 105 active contracts, 32 contracts (12.5% of total 257 PSC contracts) were presently producing, while the remaining contracts were in the exploration phase. A total of 152 PSC contracts had been relinquished and terminated.

To date the petroleum activities have focused mainly on the western-part of archipelago; 84% of PSC producing contractors operate in the western-part of Indonesia, the remaining 16% operate in the eastern-part of Indonesia. All 32 producing PSC contracts operate in developed areas, not one in frontier area. Most of the E&P activities to date have been conducted in the developed areas. Out of the 347 petroleum contracts, only 20 contractors are working in the so-called frontier areas. These areas are generally more remote which require new-sophisticated technologies needed to cope with increasingly hostile environments and greater water depths. E&P costs in the frontier areas are high, adding to longer lead-time before an actual production can commence. As an example, in US Gulf of Mexico deepwater environment, a single well can cost 70 – 100 million USD, and some wells have gone far beyond that figure (Marcotte, 2001:2). Therefore, enhancing the attractiveness of these areas needs more lenient contract terms and more attractive incentives.

Moreover, Indonesia is moving toward eventual net importer status. Indonesia's forthcoming change from net oil exporter to net importer has been forecasted since at least early 1970's. It had been postponed to date, due to new discoveries and technological advances, such as enhanced oil recovery and deep-water exploitation. However, increasing consumption and a steady decline in production, coupled with lower exploration investment levels in the last few years, means Indonesia now likely to become a net oil importer. At about 1.01 million barrels of oil per day (MMBOPD) Indonesia's production by the end of 2003 of oil continued a gradual decline from its peak of 1.7 MMBOPD in 1977. Fuel consumption continued to increase to nearly 60 million kiloliters (KL) or 1.0 MMBOPD in 2003 (US Embassy, 2004:24). In 2003 Indonesia imported about 340 thousand barrels a day (MBOPD) of crude oil and 300 MBOPD of petroleum products (US Embassy, 2004:app.8.2).

To maintain its net exporter position, it is necessary for Indonesia to improve its oil reserves and production capacity from both mature and frontier areas. In mature fields, the 85/15 production sharing splits for oil and 70/30 for gas in favour of GOI of the PSC system are no longer accepted as attractive and need to be improved. At the same time, the balance between risk and reward for frontier areas, with production split 60/40 for oil and 65/35 for gas, were generally viewed as insufficient to attract major investor, due to small reserve accumulations and high infrastructure costs (US Embassy, 2004:16).

The results of the Indonesia's petroleum E&P activities had given significant contributions to the GOI in terms of GOI revenues. As late as 1980's oil and gas was still the biggest single export commodity, contributing to about 49% of the Indonesia's export earnings (US Embassy, 2004:1). However investment levels in the 1990's have not been sufficient to prevent the decline of productive capacity and exploration activity. In 2002 Indonesia's oil and gas revenues were 74.2 trillions IDR; they were around 25% of the Indonesia's domestic revenues, declining from 31% in 2001. The value of oil and gas export earnings also declined to 21.2 % in 2002, compared with 22.4% in 2001 (Table 1.1). Thus, additional risk capital is needed to further increase the level of petroleum E&P activities.

To do so, to attract new investment, GOI should offer policies that improve the Indonesian PSC contract terms to make it more competitive; improve GOI inter and intra ministry coordination to maximise efficiency and streamline new investment; tax consolidation application; and reinforcement of contract sanctity by honouring existing contracts, including LNG sales contracts, tax terms and refund value added tax (US Embassy, 2004:16 - 17).

Also as illustrated in Table 1.1, the Indonesian PSC has become less competitive; although there was an increasing tendency on oil price in the last few years, total new petroleum contracts signed declined from its peak 29 contracts in 1997 to only one contract in 2002. Due to commencement of new incentive package (IP5) in 2003, the contract signed increased to 16 contracts in 2003, but the exploration activities levels were still low.

An overview of worldwide petroleum activities showed Indonesia's competitive position has been deteriorating steadily for the past two decades. Table 1.1 shows declining trend of exploration activities, from 145 wells in 1998 to 75 wells in 2002 and to 41 wells in 2003. Also, as shown by Hasan (2001:20-22), Indonesia's E&P activities share among a group of 15 petroleum producers (Columbia, Trinidad, Norway, UK, Angola, Cameron, Egypt, Nigeria, Tunisia, Malaysia, Pakistan, Thailand, Australia and New Zealand) had continued to decline since the end of 1970's.

According to Hasan (2001:23-26), the declining trend of Indonesia's competitive position was clearly not attributable to oil market conditions, the amount of available risk capital for worldwide oil industry and Indonesia's geological potential and political condition, but was due to deteriorating investment climate associated with increased bureaucracy, excessive involvement of Pertamina in exercising its management prerogative, the procurement procedure of goods and service and others.

Table 1.1: Indonesia's Exploration and Production Activities 1993-2003 (BP Migas, 2004; and US Embassy, 2004 and 1999)

Year	Oil Price	Contract Signed	Seismic 000km	Exploration Well	Oil Prod. Barrel/day	Gas prod. TCF/year	O&G Rev/ GOI Dom.Rev.	O&G Rev/ GOI Export
1993	16.64	11	188	114	1,534	2.181	31.4%	26.5%
1994	16.08	4	68	75	1,611	2.319	22.3%	24.2%
1995	17.23	20	63	80	1,625	2.573	20.4%	23.0%
1996	20.42	15	61	100	1,575	2.524	22.0%	23.5%
1997	19.10	29	469*	100	1,556	2.547	25.7%	21.8%
1998	13.38	22	307*	145	1,537	2.489	32.7%	16.1%
1999	17.72	6	175*	89	1,515	2.708	26.3%	20.1%
2000	28.00	5	166	76	1,299	2.676	31.2%	23.1%
2001	24.01	10	284	96	1,222	2.734	31.3%	22.4%
2002	25.04	1	NA	75	1,252	2.900	24.6%	21.2%
2003	28.68	16	NA	41	1,156	3.300	20.8%+	NA

** Data include 2-D and 3-D seismic activities*
+ Budget

Partowidagdo (1993); Yuwono (1998); as well as Dharmadji and Parlindungan (2002) made comparisons on fiscal regimes on some Asia Pacific countries involving cash flow analysis. These studies showed that Indonesian PSC system for conventional area was the least attractive, compared to China and Malaysia. However for the frontier areas Indonesian PSC offered better terms than those two countries (Yuwono, 1998: 57-59). The studies suggested that GOI needed to develop more competitive contract terms; including, among others, decreasing the amount of the DMO obligation, increasing the DMO price, improving the contractor production sharing split, and additional exploration incentives by allowing limited tax consolidation or removal of the ring-fence of the PSC especially in frontier areas.

World Bank (2000: 21-24) in 2000 conducted a study, which concluded that the recent structure of Indonesian PSC was becoming more complex; some areas were often contradicting, due to the addition of various provisions to the original structure in order to keep the terms competitive over time. Some provisions of PSC terms were not sufficiently progressive. The simulation with data field model showed, under existing PSC variables, the GOI share of profit oil for less profitable ventures when oil prices were low, was just as high as its share for highly profitable ventures when oil prices were high. This aspect causes strong disincentives for investment at low-oil prices conditions. To increase investment in the low-oil prices conditions, redesigning some variables of PSC are needed. The World Bank recommended GOI to retain the basic principles of the PSC system; redesigning terms including reducing the FTP rate for both oil and gas, increasing the DMO price to export price, application of investment credit to all areas and linking GOI profit share directly to a measure of achieved cash flow.

Furthermore, as Machmud study's (2000:183, 189-190) showed that although Indonesia offering better terms for frontier areas as compared to Malaysia and China, but a closer examination behind the contract revealed that the investment climate, opposed to Malaysia and China, Indonesia was known to have *x* factor in which makes it difficult for investor to calculate the actual cost. Such a situation proved extremely damaging to petroleum Indonesia's attractiveness. To increase the production capacity, it was recommended that climate for petroleum investment should be improved, including strict observance of the contract terms, limiting Pertamina's involvement in PSC affairs to approval of work program and budget, and exercising its management prerogative through post auditing. Machmud also suggested that a forum be created to review periodically the contract terms, as condition may change from time to time beyond the control of either party.

In the macroeconomics, favourable and unfavourable conditions originating within Indonesia has emerged unexpectedly during the last several years. Indonesia's economic collapsed in 1997, and GOI was forced to turn to the International Monetary Fund (IMF) for an emergency debt-relief package totalling to $43 billion. This condition made the financial strength of the GOI decreased significantly. Moreover the Indonesia's people power forced the government to do political reformation process and Suharto was forced out from office and was replaced by B.J.Habibie as president of Indonesia in May 1998. Political changes rapidly evolved; B.J.Habibie initiated a genuine democratic process to elect parliament and a president in the June 1999 election. The full parliament then elected Abdurrahman Wahid as president, but later in July 2001 he was impeached by the parliament and replaced by Megawati. Democratic, peaceful and smooth Indonesia's parliamentary elections as well as first and second rounds of presidential election were successfully conducted in April, July, and September 2004. As the result, Susilo Bambang Yudhoyono replaced President Megawati. The new government and parliament give strong promising points on business investment climate in Indonesia.

As part of implementing the process of reformation in Indonesia and enhancing national unity, in 1999 the GOI promulgated the Law number 22 and 25 and the Oil and Gas Law Number 22/2001. The Law number 22/1999 provided the provincial government with greater authority to manage their internal affairs, except in certain areas. The Law number 25/1999 addressed that the sharing or allocation of revenue between the central and regional governments. While the Oil and Gas Law Number 22/2001 replaces Petroleum Law No. 44/1960 and Law of Pertamina No. 8/1971. This new law eliminated Pertamina's monopoly over the upstream and downstream sectors and transferring Pertamina's responsibility for administering cooperation contracts to a new Implementation Agency, named *Badan Pelaksana Kegiatan Usaha Hulu Minyak dan Gas Bumi* (BP Migas). By the Government Regulation number 31/2002; the BP Migas was put into action in August 2002.

Security remained a major concern for investors, particularly following the terrorist bombing attack in Bali in October 2002, Hotel J.W. Marriott Jakarta in 2004, Australia's Embassy in Jakarta on 9 September 2004; and other part of Indonesia. Renewed military operations in Aceh, separatism, communal violence in Papua and others continued to challenge national unity. These conditions reduced the attractiveness of petroleum E&P business in Indonesia.

To summarise, Indonesia had been successful in shifting the contractual equilibrium towards greater benefit to the state. The PSC system not only had become, over the last 30 years, probably the most dominant form of granting access to petroleum E&P to petroleum international companies in developing countries; but also had been successful in inviting the risk capital for petroleum venture E&P in Indonesia that resulted in significant contribution to GOI revenues, especially during 1970s. However the success had been declining since then. Although the Indonesia's petroleum geological potential was valued still remained attractive, but under the influence of outside and domestic pressures, the Indonesian PSC system generally viewed as insufficient to attract investment both for conventional and frontier areas. The problem issues could be categorised into three aspects: commercial performance attractiveness, the PSC system attractiveness itself and the investment climate aspects. In commercial attractiveness, the Indonesian PSC was valued insufficient to attract investment, due to the risks and rewards sharing and the division of benefits between parties of the PSC contract did not give enough profit to the petroleum company. While in the second and third aspects, under current Indonesia's condition (geological potential, economic, social and political) the attractiveness of the Indonesian PSC system itself was decreased and the current Indonesia's investment climate was not conducive to do business.

Indonesia should increase its oil reserves and production capacity in order to maintain its net exporter position. As the prospects and the pace of petroleum development would depend on the successful efforts to attract the needed capital. Meanwhile risk capital is mobile and the willingness to put real money at risk in the midst of risk capital scarcity must be made under the attractive terms. This in essence suggests that GOI must offer more attractive petroleum contract system, offer better incentives and resolve all the problems faced by the petroleum industry today. Therefore the problem issues mentioned above need to be analysed and to be solved.

1.2. Problem Statement

With the foregoing background, the problems that are identified in this study involve the following issues:

1) Looking back over the past four decades since 1966, how were the commercial performances of the Indonesian PSCs? Did they fulfil sufficient profitability for the contractors and income for GOI?
2) Which variables of the Indonesian PSC must be considered and enhanced as incentives in order to increase the attractiveness of the petroleum E&P venture in Indonesia and still give sufficient incomes to the GOI?
3) Given recent Indonesia's geological potential as well as the economic, social

and political conditions, is the existing Indonesia's PSC still efficient to attract investors in engaging Indonesia's E&P investments? Or should it be changed to other contract types?

4) Which aspects of the Indonesia's petroleum investment climate need to be improved?

1. 3. The Objective, Scope and Importance

The study is concerned primarily on the commercial attractiveness of the Indonesian PSC system. Given, profitability is the petroleum company's main concern to do business and the government net income is the GOI main concern; therefore revenues from the petroleum E&P venture should generate sufficient amount to cover both, profit for the contractor and net income for the GOI. These two sides should be balanced.

Another business principle underlying the study relates to the phenomena inherent in the nature and development of petroleum venture. The upstream petroleum E&P venture is capital intensive and high-risk industry. In addition, the petroleum contract such as PSC links host government (owner of the petroleum resources) and private multinational companies which contribute capital, technology and equipment necessary for petroleum E&P activities in a sector where the stakes and risks as well as the possible profit margins can be very high. Their relationship has often changed due to the difference in their objectives and given the long-term nature of the agreement, the position of the two parties may change and the balance of power may shift from one party to the other. Furthermore, the relationship is vulnerable, subject to various external factors such as changes in oil prices, national and international politics, and other events.

The petroleum contract is complex legal document designed to govern a long-term relationship, negotiated on the basis of existing conditions and with assumptions of factors that will not be confirmed for many years to come. Therefore, the framework surrounding the petroleum E&P venture can be considered as part of a dynamic process, in which the change in the pattern of relationship between the government and company could shifty bargaining positions of the parties and dissatisfaction on the contract terms & conditions are sometimes unavoidable.

Given such problems statement above, the main objectives of this study are as follows:

1) To evaluate the commercial performances of the Indonesian PSCs systems since its first application up to 2003.
2) To identify which Indonesian PSC variables need to be improved as incentives in order to increase the attractiveness of the Indonesian PSC.

The balance between risks and rewards and the division of benefits between parties of the Indonesian PSC contract was analysed with the framework of principal-agent model theory that incorporating incentive structures and risk-reward sharing. The economic yardsticks used were commonly applicable in project economic evaluation involving net present value (NPV) of contractor's entitlement, internal rate of return (IRR), ratio of contractor's entitlement to gross revenues (contractor take) and pay out time (POT). Under the premise, higher risk should be balanced with higher reward, petroleum E&P venture includes higher risk premium than ordinary businesses that translates to higher minimum required rate of return. Each company has its minimum required rate of return. The following lists the minimum required rate of return of investment in petroleum E&P venture as suggested by Jones (1993:9):

High risk : 30% - 40%
Medium risk: 20% - 30%
Low risk : 15% - 25%

While from the GOI view is ratio of government income to gross revenues (GOI take).

The scope in evaluating the commercial performances of the Indonesian PSC were limited to Indonesian PSC contracts signed during 1966 to 2003 period involving entire Indonesian PSC type from PSC first generation (PSC1) to PSC third generation (PSC3); together with all incentives packages, from incentives package 1

(IP1) to incentives package 5 (IP5). The PSC contracts were categorised by PSC contract type, operation years, production type (oil only, gas only, or oil and gas), production rate, and location of operation (western-part and eastern-part of Indonesia). Due to the trend of risks and costs of extension contract are different in the new contract, the study focus only to the new contracts; it excluded the contract extension.

The scope in identifying which PSC variables need to be improved as incentives were limited to the improvement on the first tranche petroleum, investment credit, depreciation method to recover the capital expenditures as well as contractor production sharing split, price of DMO, length of DMO price holiday and the tax rate respectively.

The scope of the incentive especially for exploration phase was limited to tax consolidation application in exploration activities in frontier areas. Currently, the Indonesian PSC is ring-fenced for cost recovery and tax purposes. Tax consolidation means that expenditures in non-producing contract(s) can be deducted from the income in producing contracts of the same contractor(s) for determination of taxable income. Applying tax consolidation will decrease the exploration cost of the contractor since some of the cost is effectively borne by the government due to decreasing tax payment from producing contract. It implies with risk sharing between government and the petroleum company. According to IPA (1995:app.1), in 1995, 31 countries applied tax consolidation in their petroleum ventures, while 14 countries did not. Monte Carlo simulation was used to identify the impact of the tax consolidation application in frontier areas not only on the income of GOI and contractor’s profitability but also to quantify the risk involved and compared it with the impact of increasing the contractor’s production sharing split.

Monte Carlo simulation is a technique to calculate the uncertainty in a forecast of future event. It is effective in assessing risk and modelling uncertainty. The strength of Monte Carlo simulation is its universal applicability and contains maximum information about possible outcomes in the result. This simulation has some advantages, such as the full range of each uncertain input parameter is sampled and used in generating the probabilistic model outcome, the ease of implementation, any input-output model can be utilised in the Monte Carlo process and the Monte Carlo approach is conceptually simple and easy to explain.

As noted earlier the Indonesian PSC was based on two legal frameworks. The first legal framework of the Indonesian PSC system is the Article 33 of the 1945 Indonesian Constitution, which places the land and water, and natural riches contained therein shall be under the jurisdiction of the state and utilised for the greatest welfare of the people. The interpretation of Article 33 of UUD 1945 during the development of regulatory framework has been rather difficult, since the term of *under the state's jurisdiction* could have numerous meanings, starting from the ownership and direct or indirect exploitation by the state to the understanding that the importance thing is that the state regulates and controls branches of production important for the state and affecting the life of most people. The latter seems to have been used as underlying principle for the government in setting up the policy for inviting the private capital to participate in the exploitation of oil and gas.

The second legal framework was the Foreign Investment Law Number 1 of 1967. The term of foreign capital investment pursuant to Article 1 of the Law 1/1967 refers to direct foreign investment in which the capital owner will bear the risk from such investment. The Foreign Investment Law distinguishes the foreign investment into two categories:

(a) Foreign capital investment for mining E&P business that is open for foreign investment based on cooperation with the government in the contract of work or other type.
(b) The government's role in the form of mining E&P business can be direct as a party in the agreement such as in the mining of hard minerals or through state owned company such as in the oil and gas and geothermal electricity generation.

In the capital investment, a good investment climate is a prerequisite, which in turn will require legal certainty in the contract implementation. Under such a premise the Foreign Investment Law provides the assurance and a number of facilities covering a number of areas (such as tax, transfer of income and capital, and operational aspects). For example, the government will not nationalise or revoke fully the right of foreign investment companies, or reduce the right for ownership or managing the subject foreign companies. In special circumstances where it is necessary to the public interest, a company may be expropriated in accordance with legal procedures and appropriate compensation paid with the amount, type and method of payment agreeable by both parties, and in the event of failures to reach agreement it will be settled through arbitration.

For that reason two other objectives also need to be explored in this study, they are:

3) To identify the petroleum companies' views with respect to the most desirable contract system that suitable given current Indonesia's economic, social and political conditions.
4) To identify which aspects of Indonesia's investment climate need to be improved.

To date there is no standard format for any petroleum contract type categories and each type may contain some of the characteristics of the other. Lan (1990: 1), Gao (1993: 10) and Johnston (1994:21-27) categorised the petroleum contract system into three main systems: concessionary or royalty and tax system (RAT), production-sharing contract (PSC) and risk service contract (RSC). In addition to three contract types above, Gao added hybrid contract that combined RAT with PSC system in one system; while Johnston (1994:21-27) added pure service contract, rate of return contract and joint venture. Joint venture and rate of return contract can use RAT, PSC or RSC systems. Pure service contract is rarely applied in petroleum E&P venture. Moreover Indonesian PSC had three variations; technical assistance contract, joint operating agreement run by a joint operating body and enhanced oil recovery contract (Johnston, 1994: 21-27). Meanwhile ESCAP (1984: 14 – 21) categorised taxation in mineral E&P venture into fixed fee; specific or ad valorem duty (royalty); income tax applied at higher rate than other industries; progressive profits tax; the resources rent tax and brown tax; as a variant of them; or combination of two or more of them. All these ESCAP contract types are RAT system with variation of taxation. Abadeer (1993:69-113) categorised the natural resources E&P contracts into operated by public company; service contract; cash bonus contract and RAT contract. In the RAT contract there are 6 variants contract types, traditional

RAT contract, royalty plus cash bonus bidding contract, mixed RAT contract, profit sharing contract, resources rent contract and PSC. Recently coal-mining contract in Indonesia applies contract of work (COW) system, this system is analogue with RAT system in petroleum, due the ownership of the resources is on the contractor side. In agriculture, since a long time ago there are three main contract forms: direct cultivation, fixed rents tenancy, and sharecropping system. Compared to natural resources contracts, the direct cultivation is equivalent to operated by public company, fixed rent tenancy is equivalent to RAT while sharecropping is equivalent to PSC (Bindemann, 1999:31). Therefore in identifying the petroleum companies' view with respect to the most desirable contract system, the scope of the alternatives petroleum contract system to be chosen limited on three alternatives petroleum contract systems, they are the Modern RAT, recent PSC and RSC system.

To support the analysis, in identifying the petroleum companies' view with respect to the most desirable petroleum contract type, the study used Analytic Hierarchy Process (AHP) in the benefit-cost-risk framework. The AHP is a powerful and flexible decision making process to help people set priorities and make the best decision when both qualitative and quantitative aspects of a decision need to be considered. By reducing complex decisions to a series of one-on-one comparisons (pair wise comparison), then synthesizing the results, AHP not only helps decision makers arrive at the best decision, but also provides a clear rationale that it is the best. Designed to reflect the way people actually think, AHP was developed in the 1970's by Prof. Dr. Thomas Saaty and continues to be the most highly regarded and widely used decision-making theory. The tool has successfully been used in multi criteria's decision making such as in developing public strategy, developing business strategy, project planning, project risk management, construction planning, design and the development of new product, decision-support system in the petroleum pipeline industry, the priority setting such as in defence planning and agriculture biotechnology research; human resources allocation, conflict resolution, supporting medical technology, route selection, determining the best sport record and many others. Ultimately the tool can support decision makers who face multi criteria decision problems with a limited amount of information.

The scope on identifying investment climate's aspects that need to be improved was limited to some investment climate’s aspects of petroleum E&P business in Indonesia.

The result of the study is intended to serve as useful input for decision makers in Indonesia, including parliament, central government and their agents such as Ministry of Energy and Mineral Resources, Ministry of Finance, BP MIGAS, Tax authorities, Ministry of Manpower; provincial government (*Gubernur*), regional/local government (*Bupati*), to assist in the formulation policy on petroleum E&P business; as well as to stakeholders of petroleum E&P business involving the multinational, domestic and national petroleum companies and others, aimed at maintaining high level of petroleum E&P investment in Indonesia.

1.4. The Outline of the Study

The outline of the study is organised into five chapters. As already written above, Chapter 1 describes the background; the problem statement; the objective, scope and the importance; and the outline of the thesis.

Chapter 2 provides reviews of issues in petroleum E&P venture and its contractual arrangement, theoretical and methodological framework foundations that are grouped into four sections. The first section describes in brief the principal-agent model theory incorporating incentive structures and risk-reward sharing; the petroleum E&P life cycle chain and risk allocation; the conceptual issues in petroleum E&P contract consists of some principles in petroleum E&P contract, application the principal-agent model in petroleum E&P contract, economic rent, and rate return of investment; and the petroleum E&P contract arrangement. The second section describes the development and role of petroleum E&P business in Indonesia, the Indonesian PSC terms and variables, the financial diagram flow and model of the Indonesian PSC and some literature reviews of the past works on the Indonesian PSC analysis. The third section presents the theoretical and methodological framework foundation of decision analysis under uncertainty and risk. It is grouped into two sub sections. The first sub section provides the need, the theoretical and methodological framework foundation of the risk analysis using Monte Carlo simulation to investigate the impact of tax-consolidation application in petroleum E&P venture in frontier areas. While the second sub section describes the need, theoretical foundation and methodological framework of the Analytic Hierarchy Process in the benefit-cost-risk framework to identify the petroleum company view with respect the most desirable petroleum contract type for Indonesia. The fourth section presents the investment climate especially in petroleum E&P business in Indonesia.

Chapter 3 discusses the methodology of the study, while the result and finding are discussed in Chapter 4. Finally the conclusion and recommendation are presented in Chapter 5.

CHAPTER 2

THE LITERATURE REVIEW

This chapter describes in brief reviews of issues in petroleum exploration and production (E&P) venture and its contractual arrangement, theoretical and methodology frameworks that were used in this study. The presentation is divided into four major sections.

The first section describes the host government and the petroleum company relationship in the upstream petroleum E&P venture including the principal-agent model theory; the petroleum E&P venture life cycle and risk allocation as well as the conceptual issues of petroleum E&P contract that consists of some principles in petroleum E&P contract, application the principal-agent model in petroleum E&P contract, economic rent and rate return of investment respectively; and the petroleum E&P contractual arrangement.

The second section presents the Indonesian Production Sharing Contract, including the development and the role petroleum E&P business in Indonesia since the first oil discovery in Indonesia in 1885 up to 2003, the salient features of Indonesian PSC, and the financial model and diagram flow of the Indonesian PSC system.

The third section presents the theoretical and methodology framework foundation of decision analysis under risk and uncertainty. There were two methods used: first was the risk and uncertainty analysis in petroleum exploration investment decisions. Aimed at determining the impact of removing provision on tax ring fencing in the petroleum contract, the tax consolidation application, the study applied the simulation method known as Monte Carlo simulation. The other analysis was the application of Analytic Hierarchy Process (AHP) in the benefit-cost-risk framework to identify the petroleum companies' views with respect to the most desirable petroleum contract type for Indonesia. Therefore the third section was grouped into two sub section. The first sub section provides the need, the theoretical and methodological framework foundation of the risk analysis using Monte Carlo simulation to investigate the impact of tax-consolidation application in petroleum E&P venture in frontier areas. While the second sub section describes the need, theoretical and methodological framework foundation of the Analytic Hierarchy Process in the benefit-cost-risk framework to identify the petroleum company view with respect the most desirable petroleum contract type for Indonesia.

Finally, the fourth section examines in brief the investment climate of the petroleum E&P business in Indonesia.

2.1. The Host Government and the Petroleum Company Relationship in the Petroleum Exploration and Production Venture

2.1.1. Principal – Agent Model Theory

According to Laffont and Martimort (2002:1), for many economists, to day economics is to a large extent a matter of incentives: incentives to work hard, to produce good quality product as well as to study, to invest, to save and others. Therefore a central question of economics becomes: how to design foundations that provides good incentives for economic agents. Salanie (2005: 5) defined the Principal – Agent model in general is a Stackelberg model in which the *leader* (who proposes the contract) is called the *principal* and the *follower* (the party who just has to accept or reject the contract) is called the *agent*. Specifically Bindemann (1999:35) defined the Principal – Agent theory deals with the actions of a principal, who own an asset and an agent, who works with that asset and/or make decisions, which will affect the value of the asset. The theory focuses on designing the optimal contracts between the two parties, the principal and the agent.

The starting point of incentive theory corresponds to the problem of delegating a task to an agent with private information. There are two types of this private information: first the agent can take an action unobserved by the principal, the case of *moral hazard* or *hidden action*; or second the agent has some private knowledge about his cost or valuation that is ignored by the principal, the case of *adverse selection* or *hidden knowledge*. Incentive theory considers when this private information is a problem for the principal, and how to design the optimal incentive scheme between these two parties (Laffont and Martimort, 2002:3).

Below there are brief description simple economics samples with a view to design an optimal incentive system based on the concept in most standard economics textbooks. This presentation draws heavily on the work of Bindemann (1999:41-44), who provides a clear and concise description. The first case is simple case of incentives under certainty; the second is simple case of incentive under uncertainty and parties have same attitude towards risk; and the third is simple case of incentive under uncertainty and the parties do not have same attitude towards risk.

2.1.1.1. Incentives under Certainty

In simple case there is only one principal and one agent. Assumes the agent's effort e can be observed through output $Y,$ and there are two degrees of effort e, where e=2 is a high degree of effort, while a low degree of effort is with e=0. The low degree is a symbol of shirking. The agent is paid a wage $w,$ and a reservation utility of $U=10$. The formulation of the agent's utility function is

$$U = \begin{cases} w\text{-}e \\ 10 \end{cases} \tag{2.1}$$

Output Y depends on effort e, subsequently high output is $Y(e) = Y(2)$ and low output $Y(e) = Y(0)$, then

$$Y(e) = \begin{cases} H \\ L \end{cases} \tag{2.2}$$

When the output minus the wage paid by the principal to the agent is the principal's profit π, then the profit function

$$\pi = R(e) - w \tag{2.3}$$

The principal's objective is to maximize his profit (equation 2.3) through minimizing the expected wage Ew and encourage the agent to choose the high effort level $e=2$. To reach it, he would create a contract that specify when a high level output Y_{H} *is* achieved, the agent can get a high wage w_H; and while in the case of low output Y_L is achieved, the agent can get low wage w_L. He has difficulty to determine the values of w_H and w_L that will result in maximum profit focus to the condition of incentives for the agent to choose for $e=2$. The principal has two constraints. First is the participation constraint that arises from the existence of the agent's reservation utility $U=10$. In order to encourage $e=2$ the contract should specify values for w_H if $Y(2)=H$ and for w_L if $Y(2)=L$ that provide the agent with at least $U=0$, it can be specify as,

$$w_H - 2 \geq 10 \tag{2.4}$$

The second constraint is the incentive constraint. It postulates that the utility level from working hard should be no less than the utility from shirking, then

$$w_H - 2 \geq w_L - 0 \tag{2.5}$$

From equation (2.4) we get $w_H = 12$, while with equation (2.5) we get $w_L = 10$. Then from a high effort level, profit would be get is

$$\pi_H = H - w_H = H - 12$$

While from shirking, the profit would be get is

$$\pi_L = L - w_L = L - 10$$

Therefore the contract will be optimal from the principal's view when $\pi_H > \pi_L$ or $H \geq L + 2$. It suggests, under certainty, the principal has to pay the agent at least two unit above his reservation utility to encourage a high effort.

2.1.1.2. Incentives under Uncertainty and Parties Have Same Attitude Toward Risk

In this case the uncertainty is defined as different sates of nature beyond control of the parties, the principal or the agent. It implies that *e=2* will not necessarily ensure *Y=H*. Under certainty effort could be observed through output, therefore the principal had no need to monitor the agent. Under uncertainty condition, the level of output may not or can be directly related to the level of effort. As example, assumed that there was big flood attack the cultivation; although the agent already works hard to cultivate the land, the output level of cultivation may be very low or disappeared, due to the flood has destroyed the plants. Thus, an increase in *e* only increases the probability of *Y(e)=H*. If nature determines *Y(2)* and *Y(0)* as

$$Y(2) = \begin{cases} H prob 0.8 \\ L prob 0.2 \end{cases} \qquad Y(0) = \begin{cases} H prob 0.4 \\ L prob 0.6 \end{cases} \tag{2.6}$$

Then by choosing *e=2* the probability of high output increases from 0.4 to 0.8. The modification of the agent's utility function (2.1) needs to be done, in order to incorporate uncertainty into the model. Suppose the agent wants to maximize his expected wage *Ew* minus the effort he put into his work we find

$$U = \begin{cases} w-e \\ 10 \end{cases} \tag{2.7}$$

with

$$Ew = 0.8\, w_H + 0.2\, w_L \qquad for\ e=2$$

and

$$Ew = 0.4 w_H + 0.6\, w_L \qquad for\ e=0$$

The new participation constraint becomes

$$0.8\, w_H + 0.2\, w_L - 2 \geq 10 \tag{2.8}$$

In spite of *e=2* uncertainty may yield *L* rather *H*, then the incentive constraint changes to

$$0.8\, w_H + 0.2\, w_L - 2 \geq 0.4 w_H + 0.6\, w_L \tag{2.9}$$

The contract has to specify the agent's state-contingent wages that would result in higher utility under *e=2* than under *e=0* (w_H for *Y(2)=H* and w_L for *Y(2)=L*).

Given that equation (2.8) means that $w_L = 60 - 4\ w_H$ and (2.9) means $w_L = w_H - 5$, then the optimal contract would be the one that sets $w_H = 13$ and $w_L = 8$.

From two examples above, it can be seen that the principal can control the agent without extra monitoring. Under certainty the principal can observes the agent's effort through output, while under uncertainty the high agent's effort can be encouraged through the right specification of the agent's state-contingent wages. In the first case (under certainty), the wage bill for the principal is $w_H = 12$ and $w_L = 10$, and in the second case (under uncertainty) is $w_H = 13$ and $w_L = 8$. While the expected wage bill, in both cases is similar, under certainty $Ew = w_H$ and under uncertainty $Ew = 0.8\ w_H + 0.2\ w_L$. It can be concluded that the economic incentive mechanism is not costly to implement as long as the principal and the agent have the same attitude towards risk.

2.1.1.3. Incentives under Uncertainty and Parties do not Have Same Attitude toward Risk

When one of them is risk averse, then the structure of the contract will change. To accommodate it, we introduce subjective probabilities that measure the likelihood each of them to realization of the two states of nature, *H* and *L*. For the principal, *P*,

$$Y_P(2) = \begin{cases} H prob 0.8 \\ L prob 0.2 \end{cases} \qquad Y_P(0) = \begin{cases} H prob 0.4 \\ L prob 0.6 \end{cases} \tag{2.10}$$

Assumed that for the Agent, A, is more risk averse than the principal,

$$Y_A(2) = \begin{cases} H prob 0.7 \\ L prob 0.3 \end{cases} \qquad Y_A(0) = Y_P(0) \tag{2.11}$$

Due to the agent is more risk averse than the principal, then the agent expects greater compensation compares to the first cases. The equation becomes,

$$Ew_P = 0.8w_H + 0.2\ w_L > O.7\ w_H + 0.3w_L = Ew_A$$

From this equation can be showed that the wage bill expected by the principal is higher than the expected by the agent. Equation (2.11) shows

$$Ew_A = O.7\ w_H + 0.3w_L \qquad \text{for } e{=}2$$

and

$$Ew_A = O.4\ w_H + 0.6w_L \qquad \text{for } e{=}0$$

The new participation constraint becomes

$$O.7\ w_H + 0.3w_L\ - 2 \geq\ 10 \quad \text{or} \quad w_H\ = (12\text{-}0.3\ w_L)/0.7 \qquad (2.12)$$

And new incentive constraint

$$O.7\ w_H + 0.3w_L\ - 2 \geq\ O.4\ w_H + 0.6w_L \quad \text{or} \quad w_H\ = 2/(0.3 + w_L) \qquad (2.13)$$

Figure 2.1 shows the graphical presentation of the combination of w_H and w_L that maximize *e* (to the left of (2.13) and are acceptable contracts for the agent (above (2.12) as well as the optimal contract (triangle above point *E*). The principal's choice of w_H and w_L that will minimize his expected wage bill Ew_P is represented by line labelled (2.14), that is

$$\text{Min } Ew_P = O.8\ w_H + 0.2w_L \qquad (2.14)$$

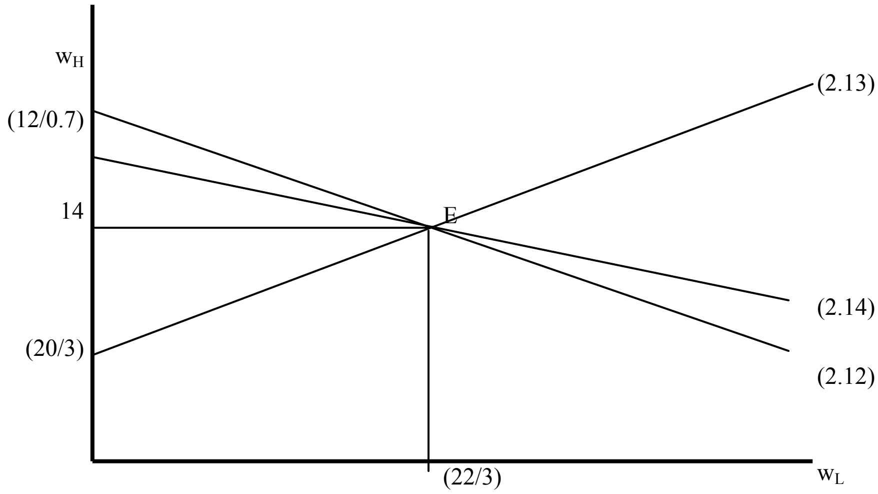


Figure 2.1: The Optimal Incentive Structure (Bindemann, 1999:44)

Figure 2.1 shows Ew_P is minimised at point E. Hence the principal would choose a contract with $w_H{=}14$ and $w_L = 22/3$, and

$$Ew_P = O.8\ w_H + 0.2w_L = 12.66 > 10 + 2$$

Above presentation shows that the agent's reservation utility is 10 and his high effort is 2. In the first case, under certainty where effort is perfectly correlated with output, the principal has to pay the agent *10+2* in order to encourage maximum effort. The similar condition also occurs in the second case, 12, under uncertainty where parties have same attitude towards risk. While in the third case, under uncertainty where the agent more risk averse, the Ew_P, the 12.66 shows us that the principal's *Ew* over the agent's reservation utility plus his effort. The insight following this is that the agent is risk averse and therefore requires compensation for taking a random wage contract. It can be seen from the difference 12.66 – 12 that in turn can be interpreted as the premium for being relatively more risk averse. It can be concluded that the principal-agent relationship shows that problems arise when effort is not perfectly correlated with output (Bindemann, 1999:44).

2.1.2. Petroleum Exploration and Production Life Cycle Chain and Risk Allocation

The upstream petroleum E&P venture has high risks and uncertainties. The geological conditions are uncertain with respect to structure and reservoir. The economic assessments of potential profitability of a venture are uncertain with respect to costs, probability of actually finding and producing, volume and type of petroleum and the future-selling price. Moreover it needs very large capital outlay; incomplete information; requires innovation and high technology; needs social overhead capital and environmental costs; has long lead-time and long-run sales prospect.

Figure 2.2 shows the petroleum E&P life cycle chain and the allocation of uncertainty and risk involved. The upstream petroleum E&P operation is a multi phase operation; its chained life cycle begins with exploration, followed by development, production and abandonment activities. Before execution of the exploration activities, the first step to be done is to get approval from the government to execute the contract, such as to obtain permits for the operation, to get visas for the expatriates, to import equipments, and others. The relationship between the petroleum company and government (central and local representatives), formal or informal, sometimes goes further than written contract's terms and conditions. It will be more complicated if the operation's location of the petroleum company goes across more than one regions or countries. Dealing with one region or country has enough challenge, predict the challenge of dealing with two regions or countries in a project. This process can take longer time than expected, which can result in higher cost.

The exploration expenditures depend on a large number of factors such as location (onshore, offshore, deep water, jungle location, remote areas) the use two or three-dimensional seismic, the depth of the deposit, need of high technology and others. If the operation needs more costly technology or uses an inappropriate technology, technology risk is occurred. This situation can increase the cost unpredictably. Moreover longer exploration time means the later production commences, resulting in delay of cost recovery. Financial circumstances might change during the period and make borrowing more costly than predicted. All these unpredicted higher costs than expected can be categorised as cost risk.

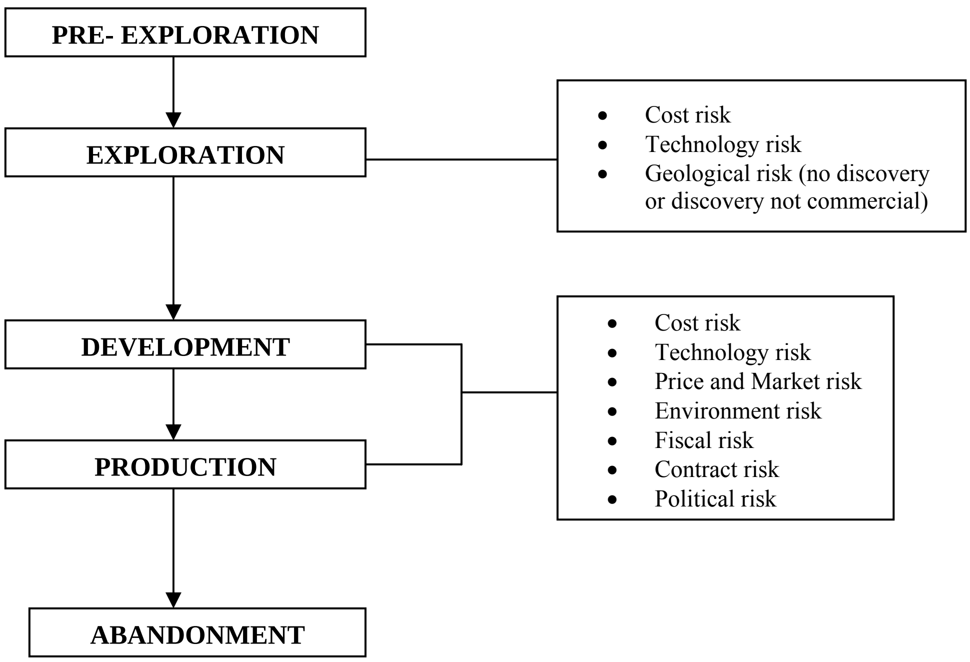


Figure 2.2: Petroleum E&P life cycle chain and the allocation of uncertainty and risk involved

The natural resources underneath are not exactly known; the main unknown factors in petroleum exploration are discovery of new resources, type of discovery, the size deposit and economic viability of development. The chance of probability discovery of petroleum exploration is very low. Ten percent success probability of finding hydrocarbon accumulation may be good in exploration. Moreover the accumulation can be commercial or non-commercial. The risk associated with the probability of finding commercial deposit is known as geological risk.

Discovering petroleum resources requires experiences supported by geological expertises. Exploration technology is introduced to reduce uncertainties in discovering these resources. However, the resources are only known after they are discovered and produced. Hence, there is a clear link between exploration activity and the settings of profit sharing and taxation, the contract terms should allow sufficient rewards for the petroleum company.

In case of no commercial discovery, the petroleum company bears all the risks during the exploration phase. Tens or sometimes hundreds millions USD may be spent without finding commercial discovery. The profitability of petroleum E&P project must cope this failure; therefore, it needs to generate enough profit not only to cover the cost of this project, but also to cover the losses incurred elsewhere.

It would take several years from the start of exploration surveys until the first hydrocarbon is produced from the contract area. For example, in Indonesia, it is reasonable to assume a time-span of five to six years from the first exploration drilling to the first petroleum produced. In case of gas discovery, it is often necessary to find first the effective way to dispose the product, as the market is not always readily available. In most cases, it takes years to find the market and financial backing; therefore leaving the status of commerciality pending on the outcome of such efforts.

The time may also be even longer, if the petroleum operation spans across more than one regions or countries to reach the market outlet through pipeline. A high set up costs are needed spreading over long period of lead times in development phase. As an example, the development of deep-sea offshore petroleum E&P involves not only innovation, but also requires high technological activities. Hence it needs large capital and high fixed costs. These are some of the reasons why petroleum E&P venture has a long lead-time. Moreover petroleum E&P venture needs social overhead capital for infrastructure such as roads, water, electricity, housing and others. Lead-time of the project may increase with this development.

In addition to high set up cost mentioned above, similar to other businesses, there is always risk linked with rising costs in the operations. In the developed area where the infrastructure is in place, the exploration and development costs may be less. Costs could also vary resulting from unpredictable events during operation. These may include longer contract or project approval process, legal matters, regulation matters, problems with community and government relation, stricter agreement with manpower regulation, condition of infrastructures, environmental issues, government interference, security matters and others. The risk linked with possibility of increasing cost unpredictably is categorised as cost risk. In minimising this risk, the petroleum company needs to recover their cost at the shortest time as possible. They also prefer contracts that display a degree of flexibility being linked to their internal rate of return. Petroleum E&P activities also have high environmental risks, and the cost could rise unpredictably as unexpected side effects during resources producing operation.

After the commercial discovery, geological risk begins to lessen. In contrast, price and political risk could intensify. The oil prices are not only influenced by domestic's demand, supply and political condition, but also by international's demand, supply and political conditions. Oil and gas prices are very volatile. The risk associated with the possibility of changes in national and international market and the possibility that the price will vary unpredictably is categorised as price risk or market risk. In case they face oil prices increase significantly and the contract is not sufficiently flexible to accommodate this change, then both parties will be concerned about the give away of revenues. While in case they faced low oil prices scenario can decrease the exploration activities in some oil field and some non-profitability of operation.

In the exploration phase the government's bargaining position is usually comparatively weak, and will be weaker so long as capital are still needed to finance the exploration and development of the resource. Once the company has reached payout, the bargaining position of the petroleum company is declining. Profitability of the petroleum company can appear too excessive to some governments and they start to review a fair return on investment and the concept of profitability. The government may issue unexpected changes in fiscal terms that influence the internal rate of return of E&P venture. The unpredictable changes on fiscal term is categorised as fiscal risk.

During the production phase the venture could also face contract risk. This risk links with unexpected revision of the contract or confusion about the contract content or non-performance of one party that raises the cost or decreases the internal rate of return of the petroleum company. Non-performance of one party, for example in case the petroleum company or the host government breaches its commitment, would very likely result in reducing benefit for both parties. The government would worry to deal with the petroleum company that has not done its obligation in the past, such as not finishing projects or trying to renegotiate its works. In contrast, the petroleum company would do the same things as well, if they find the same situation above. In case the petroleum company taken the view the potential for a future default by the government exists, it will insist on the contract either on higher share of the profit sharing or incorporating a compensation clause. While in the case government taken the view the petroleum company might be breaking its commitment, it will warrant a penalty clause as part of the contract.

A petroleum contractual agreement may have a longer term than the term of government in power when the agreement was signed. Consequently the petroleum company may also face the unpredictable changes in government and political situations, known as political risk. Such a risk deals with changing in the policies or government resulted from an election or coup, war and others. Political risk has been a major issue in international investment. Therefore in addition to geological and market or price risks, the investor needs to evaluate and manage the potential political risk when evaluating a prospective investment in a foreign country.

The political risk is not confined to the third world. At various times, developed countries such as the UK, France and Italy have raised concerns about nationalisation. By broadening the definition, the political risk includes changes in legislation that affect the industry such as taxes, labour, environmental regulations and other economic measures; the United States itself may be considered to present somewhat of a political risk (Berlin, 2003:3).

The degree of willingness to accept political risk varies from company to company. What one company finds acceptable may be too risky for another company. In assessing the degree of political risk in a particular country, the company will look at many indicators, e.g., the current activity in the host country that is affecting or is likely to affect the stability of the government (insurrection, rebellion, criminal activity), prospect for change of national or local government, past history of nationalisations/expropriations, experience of other companies in the country, political activity and trends in the region, the overall economic condition of the country, forced adverse tax changes/ price controls and others. The most common PSC response to political risk is international arbitration.

Given high-risk and uncertainties mentioned above, a petroleum E&P venture has implications as follows:

(a) The expected profit margin must be large enough to accommodate the failures elsewhere (Johnston, 1994:5–7) and must have a higher risk premium (Siebert, 1984:30).

(b) Uncertainty increases over time. A way to reduce this uncertainty is by giving the company high profit in the early of production activity (Siebert, 1984:30). It makes shorter pay out time (POT) of its investment.

(c) Investors tend to choose as smallest risk as possible. They might choose other opportunities that have smaller risk and not to invest in a high-risk country (Siebert, 1984:30). Higher risk needs more lenient petroleum contract and fiscal terms.

(d) The petroleum company can manage the high-risk investment through diversification (Siebert, 1984:30). On the other hand governments are not diversified.

2.1.3. Some Conceptual Issues in Petroleum Exploration and Production Contract

2.1.3.1. Some Principles in Petroleum Exploration and Production Contract

The financial burden and high risks as well as uncertainties appear above to be just too large to be shouldered alone by developing country that has many other priorities. Therefore developing countries have invited oil companies to share the risks by providing the risk capital for petroleum E&P activities in exchange of direct shares of potential profit under some types of petroleum contractual arrangement.

The term *contract* originates from English word that translates into *Bahasa Indonesia* as *perjanjian* or *persetujuan.* According to the Article 1313 of Indonesian Civil Code, *perjanjian* is an act of two or more persons binding themselves to one or other persons (Hasan, 2005:14). Black's Law Dictionary (1999:318) defines contract as an agreement between two or more person creating obligations that are enforceable or otherwise recognizable at law. Moreover, Samuel Williston as quoted in the Black's Law Dictionary states that a contract is a promise, or a set of promises, for breach of which the law gives a remedy, or the performance of which the law in some way recognize as a duty. While Dirdjosisworo (2003:19) defines contract is a promise or set of promises for breach of which the law gives a remedy or the performance to those breaching the promise along with sanction for execution. It can be concluded that contract is a written agreement signed by parties for the purpose of performing together legal obligations based on mutual understanding in respect to their relative rights and duties regarding future performance (Hasan, 2005:16).

As quoted by Hasan (2005:24-31) Indonesia Civil Code Book III recognises there are four universal principles with respect to the contract law: freedom of contract, *pacta sunt servanda*, good faith and consensualism. Freedom of contract means parties have the right to bind themselves legally, to determine the content, its enforcement and terms in harmony with the need, to make it in certain forms, or not subject or subject to the choice of laws and regulations. *Pacta sunt servanda* means that contracts that legally come to existence and continue to be in force must be observed. Therefore the contract is neither unbreakable nor unchangeable. According to Wehberg the *pacta sunt servanda* as general principle of law is found in all nation, while the contract sanctity is an essential condition of the life of any social community. The principle of *pacta sunt servanda* always exists in economic relations between parties of agreement. Good faith is a principle in which the parties shall perform the substance of the contract based on trust or believe or good will by the parties. Good faith of the parties is always implied in any agreement, although it has not always been stipulated. Good faith is not confined to in making the legal relationship but also applicable in exercising the right and obligation arise from that legal relationship. Consensual means having, expressing or occurring with full consent. According to Grotius the consensual principle had a religious origin, i.e. *one word be kept (pacta sunt servanda)* and *we shall keep our promise*. Given such principle, each party in the agreement shall be in charge for matters that are not executed; regardless of the failure is outside its power and unforeseeable when the agreement is signed.

More specific in petroleum E&P venture, petroleum contract is legal document that describes the overall framework in which each contracting party is to fulfil its obligations. Petroleum contract also involves economic aspects concerning costs, rewards and others to be shared by contracting parties (Lan, 1990: 19).

Petroleum contract is complex and differ from the traditional government procurement contracts, first due to their multiple phases of their operation where the production phase depends on the outcome of the exploration phase. The parties may terminate the contract if the first phase was not successful. Second the uncertainties on the existence of the resource, the volume of reserves in each discovery, and on the level of production are not specified in the contract. Third the costs vary due to the unique characteristics of each discovery and technology used. Fourth the uncertainty of the product, whether it is oil only, oil and gas or gas only. Fifth the information gaps exist between the company and the government. Usually, the company have more information about the costs and the value of the resource potential. That is why the petroleum E&P contracts should provide flexible terms and incentives to adjust to these differences (Abadeer, 1993:23).

Moreover petroleum contracts are designed to govern a long-term relationship, negotiated on the basis of existing conditions and assumed factors that will not confirmed for many years to come. Therefore, when the conditions and assumed factors changed, pressure for changing unsatisfactory terms of the contract could not be avoided.

There is essentially a similarity between the petroleum contract in developing nations and those applied in the agriculture. In the agriculture there are three forms of contract, namely direct cultivation, fixed rents tenancy and sharecropping system. Under direct cultivation system, the landlord (the owner of the land) cultivates his land alone thereby he will bear all the risks. In contrast with the fixed rents tenancy system under which the tenant rents a land from the landlord and pays the fixed rent to the landlord and he cultivates the land at its own risks.

While in the sharecropping, the landlord allows the tenant to use his land in exchange for specified share of production. The terms may vary; for example, the landlord may determine the purpose of land use and how it should be used. The landlord also may bear part of the costs that in turn will be reflected in production share he will receive and others. If bad weather destroys the crop, all parties bear the risk involved, while if the cultivation successes, the production after recovering the costs will be shared between the tenant and the landlord and can be regarded as the compensation for the tenant risk taking. Therefore sharecropping system is essentially a contract form that combines risk sharing and incentives, and the relationship between the landlord and tenant is analogue with the principal, who own the asset and the tenant is the agent who works with the asset to improve the asset’s values (Bindemann, 1999: 31-35). Comparing with the practice in agriculture, direct cultivation is equivalent to that the national petroleum company as the landlord doing the E&P activities without the foreign petroleum company. The concession/RAT system is similar to the fixed rents tenancy and PSC system is equivalent with the sharecropping.

The problem is how to design an optimal petroleum contracts including risk sharing and incentives between the principal and the agent.

2.1.3.2. Application of the Principal – Agent Model in Petroleum Exploration and Production Contract

In the petroleum E&P contract, the *principal* is the host government or government agent or the national petroleum company on behalf of the country (the host government), who own the asset (petroleum resources), while the *agent* is the petroleum company who is willing to provide risk capital and technology to explore and to produce petroleum resources. When the host government enter into negotiations with the petroleum company, expects to provide capital risk and technology for petroleum E&P activities, the host government want to guarantee that it achieve the best possible contract given the country's particular conditions.

On the other hand, to achieve successful petroleum E&P investment, prior to bidding and negotiating a petroleum contract, petroleum company should take several analyses carefully a number of elements into account and evaluate them under different scenarios such as geological potential, variation of petroleum prices, costs, technology needed, contract terms, risks of the prospect and others (Juritz, 1999:1 and Bindemann, 1999:29). The objective is to maximise revenues in each scenario. After deciding to invest, the petroleum company bids and negotiates the contract. The bargaining position of the petroleum company is the greatest in the early phases prior to contract signing and exploration phase, before the discovery of the resources.

The host government faces two constraints, first given the market for E&P capital and technology is extremely competitive, so the willingness to put real money at risk in the midst of risk capital scarcity must be made under the attractive terms; and second the petroleum company and the host government have similar objectives, maximising their revenues. Their successful negotiation will be determined by their bargaining position, negotiation skills and country specific conditions. Therefore the host government to find the optimal/efficient contract form for its country. The contract is optimal/efficient when it is impossible to improve one party's terms without making the other party worse off. As an example, assume a contract is being renegotiated and is presumed remain efficient, then the renegotiation must improve two parties conditions or one party improve its condition without the other party losing anything. In more specific can be said, assuming that the host government can exploit its bargaining position it will try to offer contract form that provide sufficient incentives for the petroleum company to sign the contract while at the same time guaranteeing the petroleum company will not appropriate all incremental benefits. Therefore incentives are one of the main contract characteristics (Bindemann, 1999:29).

The assessment of the risk involved in a project and judgment of whether potential rewards justify taking a particular risk are made by finding the probability distribution of the measures are concerned. The risks/uncertainties in petroleum E&P are the geological risk, cost risk as well as price risk, technological risk and many other risks. The allocation of these risks is a significant factor in the formulation of an optimal/efficient contract. As already mentioned earlier the contract can be judged as optimal/efficient, it has to be measured efficient by both parties. As an example, suppose one party is more exposed the price risk than the other, and then the former party is more disadvantages in carrying the price risk.

When writing a contract, the main concern of the host government will want to design a contract that his interest will be progress by the petroleum company regardless of the fact that the interest of the petroleum company deviates from his interest. The host government has to offer contract terms that are attractive enough for the petroleum company to engage the contract, therefore, the host government needs to provide an incentive to the petroleum company that will encourage him to act in the host government's interest. While in the same time the host government has to build up a monitoring system that let him to evaluate the petroleum company's performance and to keep away from moral hazard. It means the host government needs to create a system whereby the petroleum company is encouraged to maximise his efforts in order to get maximum reward that in turn will also yield maximum revenue to the host government. One way to control moral hazard is the host government has to pay the petroleum company a reward based on the performance of the petroleum company's. The better the petroleum company performs his job, the higher his income.

With reference to the principal-agent model, it means the reservation utility of the petroleum company has to be recognized. In petroleum E&P venture case the reservation utility can be replaced by the rate of return of the petroleum company expects from a comparable project elsewhere, and it is the participation constraint. At the same time the government has to solve the incentive constraint, due it will want to guarantee that it receives maximum revenue from the venture. Therefore the utility from working hard (to perform the contract) should be no less than the utility from shirking, on other word the profit of the first case has to be larger than the second case. For that reason the host government has to pay the petroleum company *x* units above his reservation utility for the contract to be optimal (Bindemann, 1999:36).

In the exploration phase, as mentions in sub section 2.1.2, the petroleum company faces uncertainties such as geological risk consists of no discovery, discovery but not commercial as well as cost increase (cost risk) might be caused due to require more expensive technology (technology risk) and some operational issues that makes cost increase and/or extension of exploration phase. The longer the exploration phase means the longer the production starts, and the longer cost can be recovered. These facts can make petroleum company's financial circumstances might changed and borrowing more costly. In contrast the host government has no direct financial risk in this phase. However, it has to monitor the operation of the petroleum company to do its work obligation as specified in the contract, such as number wells to be drilled, depth, technology applied etc.

As discussed in principal-agent model earlier, under certainty effort can be observed through output, thus no special monitoring is required. When the agent's contingent wages are correctly specified, the same result under uncertainty also can be achieved. Given under PSC system the cost can be recovered after the production exists, it is generally can be assumed that the petroleum company has no incentive to artificially make longer the exploration operation. Moreover since the entire risks during exploration phase are born by the petroleum company, the host government should be ensured in contract terms that the project could generate sufficient rewards not only to cover the cost of the project itself, but also to cover the losses incurred elsewhere.

During production phase the petroleum company might face uncertainties such as are cost increase (cost risk), price decrease (price risk) as well as contract risk, fiscal risk and political risk, in which the first two risks are the main uncertainties. In contrast with exploration uncertainties, the risks during development and production phase are shared between the host government and the petroleum company. In facing the cost risk, increasing cost is largely borne by the petroleum company, means the petroleum company needs more time to recover the cost. As example in the case there is a cost recovery limit such as 40%; it means longer time for recovering the cost is needed. As the result the petroleum company and the host government have to wait longer before they can realise their profit. Seeing that the definition of profit is total revenues minus total cost, $\pi = TR - TC$, consequently cost increase influences both parties, in which its impact is larger for the petroleum company than the host government. The recent Indonesian PSC does not have cost recovery limit, it is an attractive incentive for the petroleum company.

Under Indonesian PSC system, the host government revenues come from the FTP, host government profit share, taxes, DMO and bonuses, while the petroleum company's revenues come from cost oil and its share of profit. As profit is function of price and production, $\pi = PY$, this equation represents that the increasing price/production will increase the profit. If the prices decrease, the increase of production is not necessary. Therefore, to make the principal-agent model effective, the incentives or rewards, offered to the agent (the petroleum company) have to take into account all aspects above, and balanced them in a way that encourages maximum effort from the petroleum company while at the same time guaranteeing sufficient host government's revenues. Back to theoretical of Principal-Agent model in earlier sub section, especially relevance for the PSC system, the model states that the agent has a reservation utility specifying what return he can receive from an alternative investment. Under certainty, the principal has to compensate the agent by paying x units above that reservation utility. Under uncertainty x is greater that under certainty if maximum effort is to be encouraged (Bindemann, 1999:38).

2.1.3.3. Economic Rent

The size, the quality and the distance to the market of petroleum resources are aspects that make petroleum resources differ from each other. The resources that are of higher quality and closer to the final market are more valuable and they are usually produced first. These valuable resources will be produced in order to achieve their profitability until the point is reached where the rest of the remaining resources are only marginally profitable to be exploited. On these remaining resources there are no profits, due to the revenue from them just equals to the cost of produced the resources. On contrary, for high reserves deposits that have high quality and more close to final market, with the same price, may results extremely profitable (ESCAP, 1984:6).

Seeking economic rents is particularly prevalent in petroleum economies. For petroleum E&P venture, Johnston (1994: 5-6), ESCAP (1984:6) and others define economic rent (synonymous with excess profit) in petroleum resources E&P project as the difference between the value of production and the cost to produce it. In the literature the term economic rent has been interchangeably with resource rent, mineral rent, pure rent, true rent, economic profit and pure profit. The study used the economic rent.

Figure 2.3 shows the illustration of the allocation of revenues from petroleum E&P project for costs and division of profits. From the project point of view itself the total project's profit is the gross revenues minus the cost recovery that consists of exploration, development and production costs.

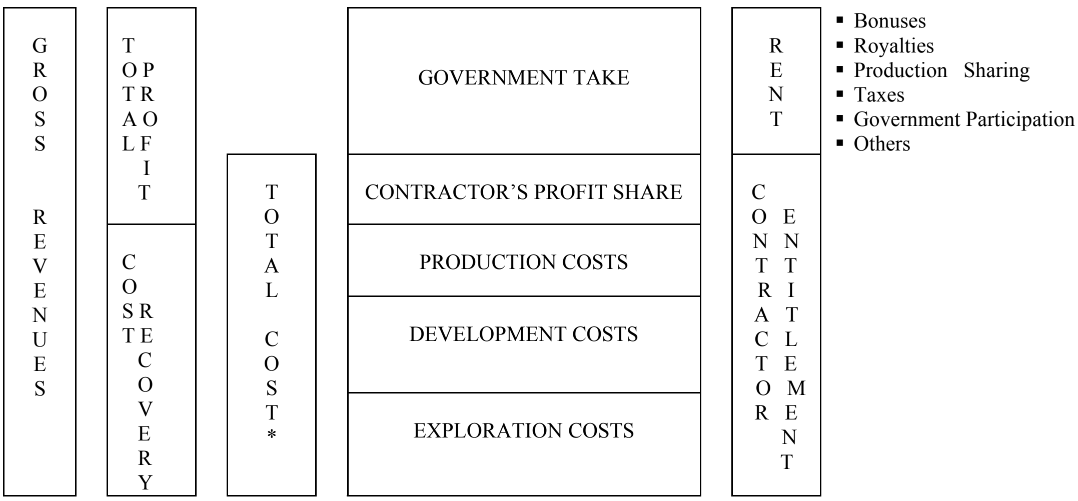
Gross Revenues of the project	=	Production x Price
Cost Recovery of the project	=	Exploration Cost + Development Cost + Production Cost
Profit of the project	=	Gross Revenues of the project – Cost Recovery of the project
or	=	(Production x Price) – (Exploration Cost + Development Cost + Production Cost)

When a petroleum company works as a contractor for the national owned company (or government agent) on behalf of the host government, the total profit must be shared between the petroleum company and the host government. The contractor would then be entitled to receive the costs spent for exploration, development and production as well as their share of profit (contractor's profit share), namely contractor entitlement. This is illustrated as follows.

Contractor Entitlement	=	Contractor's profit share + Cost Recovery
or	=	Contractor's profit share + Exploration Cost + Development Cost + Production Cost

From the host government, the remainder of gross revenues after taken the contractor entitlement is called the Economic Rent (Government Take*)*,

Economic Rent (Government Take)	=	Gross Revenues – Contractor Entitlement
or	=	(Production x Price) – (Contractor's profit share + Exploration Cost + Development Cost + Production Cost)



* *Total cost from the perspective of the government*

Figure 2.3: Allocations of revenues from production petroleum E&P project (Johnston, 1994:7)

The objective of any government would be to optimise the economic rent through royalties, sharing of production, taxes, government participation and many others. The subject would then be how such economic rent could be captured efficiently. Higher take for the government through better production sharing split in favour of the government and higher tax rate may result in maximising the economic rent. Such a condition however may discourage investment, resulting in reduced level of petroleum activity, which in turn would reduce the government's revenues in the long run. Any system must provide an appropriate balance that involves balancing the possibility of deterring investment that can reduces the revenues as a whole against collecting too little the economic rent through overly generous agreements. For that reason the important dynamic in international negotiations and contract design is how petroleum contract can ensure the government gets a part from the outcome of petroleum venture while at the same time it still gives a reasonable profit to the petroleum company (Johnston, 1994:5–7), (Marcotte, 2001:1-2) and (ESCAP, 1984:7).

In the case that there is perfect information and no uncertainty, the host government can easily calculate in advance how much the economic rent would be yielded by petroleum E&P project and can collect this economic rent from the company. But in reality, the E&P project has a very high degree of uncertainty that causes the host governments and petroleum companies to behave differently.

Petroleum companies may be risk averse. The more risky the petroleum E&P venture is the more return will the petroleum company require if they contribute in the venture; it means the higher will be the risk premium. Under uncertainty the economic rent value of an E&P project is a variable and two important determinants of the economic rent value are the risks of the project and investor's attitudes toward risk. The more risky E&P ventures are, and the more risk averse investors are, the smaller will be the economic rent value for the government (ESCAP, 1984:8).

In maximising the economic rent, the government and contractor must consider the influences of petroleum E&P variables on their return of investment. Partowidagdo (2000:1-4, and 1996) modified a causal approach diagram from Naill that illustrates the framework of petroleum business in a developing country (Figure 2.4). The plus or minus sign represents a relationship between the two variables linked by the arrow. According to him, a change in variables in petroleum E&P

venture such as unproved reserves, discovery rate, proved reserves, cost, investment, and production will influence positive or negative changes on others.

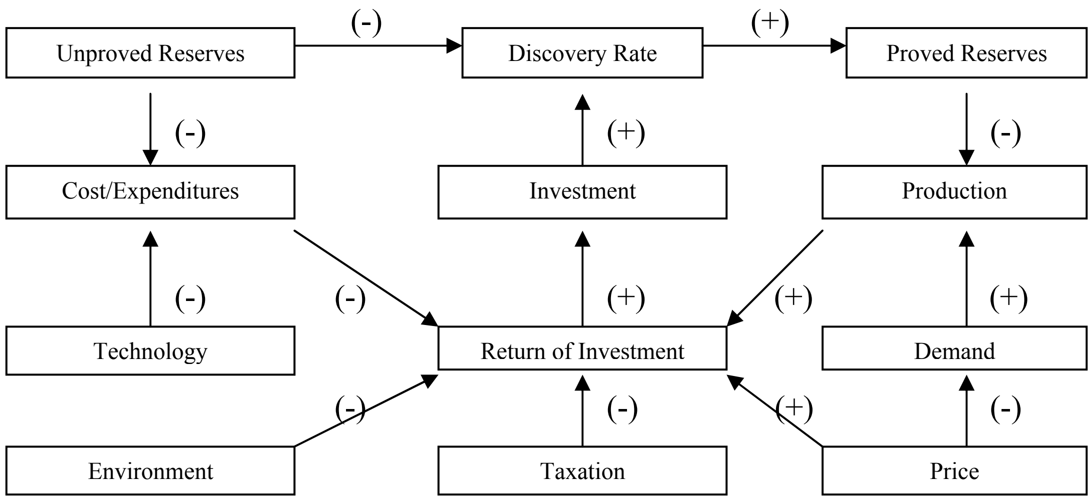


Figure 2.4: Causal-loop diagram of petroleum discovery model in typical developing country (Partowidagdo, 2000:4)

For example, production and proved reserves have a negative relationship, which means as production increases proved reserves would decrease. An increase in discovery rate will increase proved reserves, since they have a positive relationship. Unproved reserves decrease as discovery rate increases, and the proved portion of resources expands. If the proved reserves are depleted, then cost of exploration increases, because the explorers will look for more difficult or costly areas and in turn it will decrease the return of investment. This situation occurred in Indonesia, due to the maturing of western-part; increasing exploration activities must be focused in eastern part of Indonesia that mostly located in deep water and frontier areas. Exploration costs in deep water and remote areas are more costly, the decrease in the return of investment can be halted by issuing some incentives that can decrease the exploration cost and setting up an investment climate that is conducive to do business.

If planned properly, technology tends to decrease costs. But it may also increase costs, which usually occurs when the activity faces unpredictable complex structure, needs sophisticated technology in rural area, deep water, frontier area, or in the case of lack of infrastructure. Again this situation needs incentives that can decrease the exploration and development cost.

In addition, while fulfilment of environmental regulations tend to increase costs, it is essential that the environment be preserved for the future generation. The increase in environmental cost should be temporarily or near term, as environment is preserved, the overall cost to maintain would decline in the long run.

As the revenue increases due to the rise in production and price, the return on investment would improve. Such improved return of investment would usually result in increased investment in the exploration, and in turn, result in better discovery rate. In order to increase discovery rate, in case of declining reserve-to production ratio (R/P), exploration activity needs to be increased to add the proved reserves. Incentives to decrease the exploration cost and an investment climate that is conducive to investment are needed. While high price of petroleum would reduce the demand, and in the long-term it could reduce the return of investment of petroleum venture.

The return on investment will decrease as the tax rate increases, thus resulted in decreasing the attractiveness of the petroleum investment in the country, especially if the petroleum's reserves are not large enough.

2.1.3.4. Rate of Return on Investment

Mc.Cray, A. W. (1975), Jones, D. R. (1993:7-12), Seba (1998:155-189), Newendrop (2000:16-46) and others recommend three parameters to determine the profitability of certain petroleum E&P project proposal, namely Net Present Value (NPV), Internal Rate of Return (IRR) and Payback Period (POT).

Net Present Value (NPV), which is derived by discounting a project's cash receipts using the required discount rate, summing them over the lifetime of the proposal and deducting the investment outlay. Each company has its discount rate. In the mineral investment, expenditures would be credited through the whole life of the project, so the NPV of the project is as follows:

$$NPV = \sum_{t=1}^{n} \frac{R_t}{(1 + k)^t} - \sum_{t=1}^{n} \frac{C_t}{(1 + k)^t}$$

If the present value of net in cash flow in the future is higher than the present value of investment (NPV > 0), the project is financially feasible because it is profitable. If the present value of net in cash flow on the future is lower than the present value of investment (NPV< 0) the project is financially not feasible because it is not profitable.

Internal Rate of Return (IRR), is defined as the rate of discount, which equates the present value of the stream of net receipts with the initial outlay (NPV = 0):

$$\sum_{t=1}^{n} \frac{R_t}{(1 + r)^t} = \sum_{t=1}^{n} \frac{C_t}{(1 + r)^t}$$

where: C_t : initial cash outlay on the project

R_t : net cash flow at time t

n : project life

r : the internal rate of return

In general the IRR will be compared to the relevant levels of company's minimum required of rate of return. Each company has its minimum required rate of return. If the IRR is higher than the company's minimum required rate of return, the investment is profitable and financially feasible. If it is lower, the investment is not profitable and financially is not feasible.

In the treatment of uncertainty and risks in petroleum E&P venture, most investors are risk averse, he/she will choose the less risky project than the more risky project with the same net present value. The risk premium depends on the riskiness of the project. Higher risks must be balanced with higher rate. This risk premium represents the company's required compensation for taking the risk. The size of the risk premium is affected by actions of the government, and will be lower if commercial and political risk can be reduced. The commercial risk can be reduced by the government, for example by making exploration data freely available or by financing exploration activities. While strengthening the macroeconomic and fiscal stability are required to reduce the political risks (Baunsgaard, 2001:6). Jones (1993:11) recommended the minimum required rate of return of the investment on petroleum E&P project as follows:

High risk : 30% - 40%
Medium risk: 20% - 30%
Low risk : 15% – 25%

Uncertainty increases over time. A way to reduce this uncertainty is by giving the company high profit in the early of production activity (Siebert, 1984:30) that shortens pay out time (POT) of its investment. The POT is the time needed for all investment outflows to be compensated by back inflows, the formula as follows:

$$\Sigma \text{ Cash inflow } - \Sigma \text{ Cash outflow } = 0$$

Shorter POT is better, because the cash-outflow can be paid out in shorter time, and in turn can be invested in other projects.

2.1.4. Petroleum Exploration and Production Contractual Arrangement

Based on the owner of the petroleum resources, as shows in Figure 2.5 Johnston (1994:21-27) categorised the petroleum contract system into two major categories: concessionary or royalty and tax system (RAT) and contractual systems. In RAT system, the petroleum company through government licensing may privately own the petroleum resources. While in contractual system the government still retains its ownership of the resources, the petroleum company as the contractor of the government (sometimes delegated to national petroleum company or government agent) provides all financing and technology for the operation of petroleum E&P project.

In contractual system there are two systems, namely the Production Sharing Contract (PSC) and Service Contract. The difference between those contracts is the type of contractor receives, cash or in kind (crude). In PSC system, the profit oil in kind is shared between the government and the contractor after recovering the cost, while in Service Contract system the contractor gets fee in cash as payment for the services.

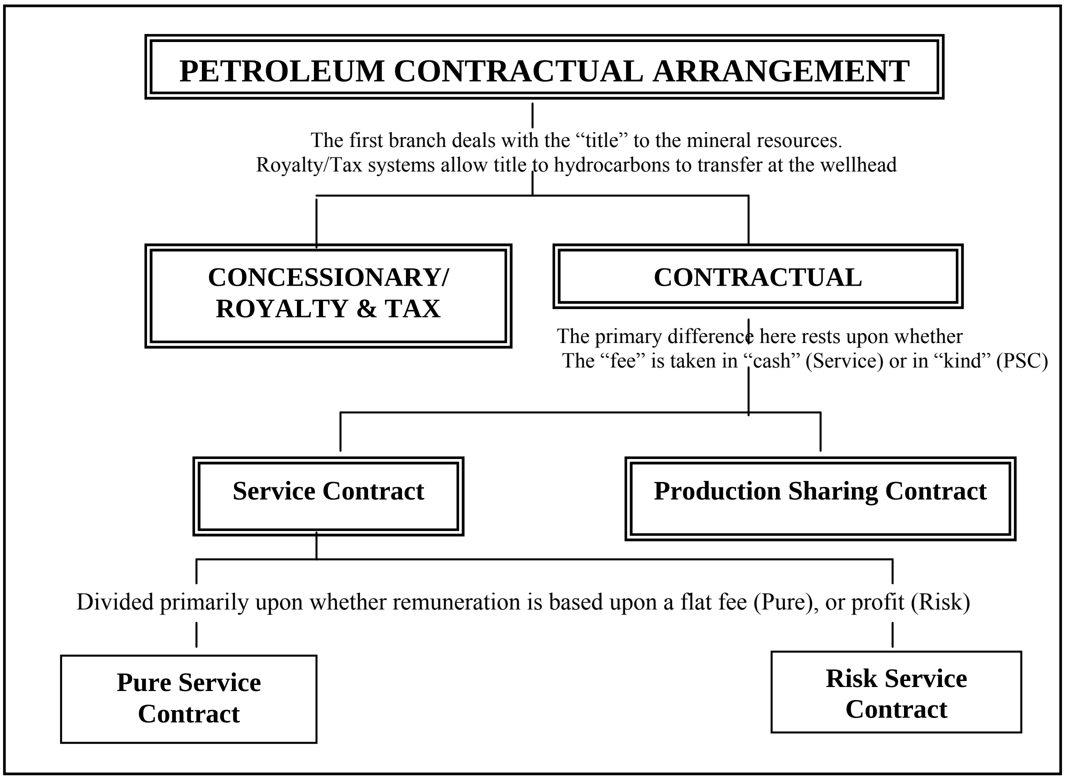


Figure 2.5: Petroleum E&P contractual arrangement (Johnston, 1994:25)

Service Contract system may further be divided into two types: Pure Service Contract and Risk Service Contract (RSC). These contracts differ in fee sharing, a flat fee in Pure Service Contract or profit in Risk Service Contract. According to Johnston (1994:24) the Pure Service Contract is rarely applied in petroleum E&P venture.

Besides the two main systems, there are other types of petroleum contracts such as Joint Venture, Technical Assistance Contract (TAC), Enhanced Petroleum

Recovery Contract (EOR) and Rate of Return Contract (RORC). These systems can use RAT, PSC or RSC systems as the basis.

2.1.4.1. Concessionary/Royalty and Tax

In RAT system the petroleum company through government licensing may privately own the petroleum resources. The government only sets up the rules for licensing, including establishment of fee for land use and degradation, and imposing royalties and production taxes without being involved with the industry itself. In this system the operation is carried out and the risk is borne by the petroleum company.

As Cottee (1992:482) said in the Australian Northern Territory Department of Mines and Energy, the word "royalty" came from an ancient royal prerogative that all silver and gold found within the realm belonged to the King. The gold and silver ownership could be transferred from the King through paying to the monarch a title some described and which became known as Royalty. According to Machmud this system is also called Royalty and Tax system (RAT), since its main features are royalty payment and taxes (Machmud, 2000:37).

Before 1950 the traditional RAT system was almost the sole contract form between developing countries' governments and international petroleum companies. At that time most petroleum E&P ventures in Latin America, North Africa, Middle East and Far East were operated by seven major companies, known as the *Seven Sister*, namely Exxon (former Standard Oil Company of New Jersey), Mobil (former Socony-Vacuum Oil Company), Gulf Oil Corporation, Texaco, Standard Oil Company of California, British Petroleum Company and Royal Dutch/Shell Transport and Trading (Machmud, 2000:34).

In its early development, there were essentially no standard form of contract, including the financial terms and the duration of contract. For example, under the RAT system applied in Indonesia in the early 20^{th} century, the term was 75 years, while in the Middle East the term varied from 60 to 82 years. Under the traditional

RAT the exclusive right provided to the petroleum company was an almost unrestricted right and excessive rights; such right granted by the government included the right to explore, mine, extract, refine, transport, export and sell the petroleum produced (Gao, 1993:29).

As the bargaining position of the government increased, the traditional RAT system began to change since 1940. Venezuela led the change by imposing in 1943 taxes in addition to royalty in 1943. A new income tax law followed this in 1948, in which the tax became 50% of the profits, later known as the concept of equal profit sharing. Saudi Arabia followed the 50/50 profit sharing scheme in 1950. The changing in RAT contract terms continued throughout the 1980s; in addition to royalty and tax, the modern RAT system may include bonus payment, pricing control and windfall profit, the latter to capture excess profits from unexpectedly high oil prices (Gao, 1993: 32).

In Thailand, the RAT system granted the petroleum company to acquire ownership right over its concession area, managerial control of the operations and expropriates most of the production. The concession area ranged from 4,000 km2 to 10,000 km2. The duration of contract was 26 years, which divided into 6 years for exploration and 20 years for production phase. The obligation of the concessionaire was to perform its obligations in petroleum exploration both in the forms of minimum expenditures as specified in the contract. Relinquishment at the end of four years operation, 50% of each exploration block for onshore area, and 35% of each deep-water block. The fiscal regime consisted of surface reservation fee, royalty, income tax, and the special remunerator benefit. The rate surface reservation fee was payable at 100,000 baht (3800 USD) per km2 per year. Royalty must be paid in cash or kind, with sliding scale rate based on production levels. The concessionaire was subject to pay tax at a rate of 50% of net profit, or 35% of profit plus 23.08% remittance tax, and was payable semi-annually. If the concessionaire had annual petroleum profit, it was then subject to payment of the Special Remunerator Benefit at a sliding rate. There were also a number special advantage clause that must be furnished to the government by the concessionaire such as a government right to purchase oil on first priority basis and preference to local goods and service, signature bonus and annual bonus, domestic supply, preference for domestic services, employment and training, Thai government participation and others (Gao, 1993:71 – 112). To summarise, the recent modern RAT contains numerous fiscal devices, layers of taxation, and sophisticated formulae

According to Gao (1993: 71 – 112) Thailand's Modern RAT system is relatively generous and a simple arrangement in terms of form, content and administration. He assumed the case of Thailand illustrated the weak bargaining position of governments with unproven reserves on the edge of the world petroleum system. The Modern RAT system serves as a useful device for attracting foreign petroleum companies to invest in the developing countries with unproven petroleum potential, geographically isolated exploration areas such as frontier, remote and deep water areas, little capital, technology and administrative expertise

Modern RAT system has also being used in the politically stable country and developed countries, such as United States, Australia and Norway and others. Through 1993 around 122 countries in the world utilised the RAT system (Gao, 1993: 21).

2.1.4.2. Production Sharing Contract

Ibnu Sutowo, the first President Director of Pertamina introduced the PSC in early 1960s and since then the PSC as introduced by Indonesia has been used as a model in various developing countries throughout the world. This type of contact has become its own rightful and unique style of cooperation in the petroleum venture (Pertamina, 1989:4). The PSC contract is intended to accommodate the Indonesia national aspiration who wishes to exploit its natural resources in accordance with Article 33 of the 1945 Indonesia's Constitution that states: *All the natural wealth on land and in water is under the jurisdiction of the State and should be used for the benefit and welfare of the people*.

The keys of the PSC system are the government ownership of the resources and the sharing of production in kind. While the government still retains its ownership of the resources; the contractor provides all financing and technology for the operation and bears the risks. Such concept of mineral ownership by the State was developed in the Napoleon era, as the French legal concept states that the Government shall own the ownership of minerals, not individuals for benefits of all citizens (Johnston, 1994:22).

The contractor explores and develops resources under general supervision of host government agency or the national petroleum company on behalf of the government. The risk during the exploration activity are borne by the contractor, while during production are shared between government and contractor. Although all operations are planned and carried out by the contractor, the host government closely monitors the contract operation through periodic reporting and submission of information by the contractor.

Important financial parameters in the contract include method of cost recovery, production sharing split, bonuses and royalty payment. The cost recovery is the repayment of the exploration, development and production expenditures of the contractor, which commences when the contract area begins its first production. The provision on cost recovery is usually described in detail in the contract. In order to provide a guaranteed income for the government from any petroleum E&P venture, some PSC has a provision that limits the amount of cost that can be recovered annually. The cost that has not been recovered may be carried forward to be recoverable in subsequent years. Such cost recovery ceiling will affect the contractor's cash flow and return on investment.

Under the PSC term, profit oil or profit gas is defined as remaining revenues after royalty and cost recovery. This profit will be shared between the contractor and the host government at an agreed formula. In addition, contractor will pay taxes on its share of profit.

Although the rules of PSC can be interpreted as being strict by some investors, the concept provides investor with an attractive opportunity for profitable operation; thereby the PSC system has been used as a model in various countries throughout the world. During 1966 – 1998 period there were around 268 PSC contracts signed in 74 countries (Bindemann, 1999:47).

Petroleum contracts, such as PSC are designed to govern a long-term relationship negotiated on the basis of existing conditions and assumed factors that will not be confirmed for many years to come. When the conditions and assumed factors change; pressure for changing unsatisfactory terms of contract could not be avoided. Indonesia is of no exception; over the time the financial terms have changed. For example, over the years Indonesia has made several revisions or amendments in the original contract. The first revision made following the drastic increase in crude oil prices in 1973; it increased Pertamina and Government's take to 85% for oil and 70% for gas. The revision also included the amended provision on companies' payment of Indonesian income tax, which would allow the US companies to meet the IRS rulings for tax credit. Following revisions involved providing additional economic incentives to meet the industry's plight for improved terms. As a result, there have been three generations and five economic incentive packages investment as well as three variations of PSC system in the development PSC system in Indonesia.

2.1.4.3. Variation of the Indonesian Production Sharing Contract

The PSC was initially developed for new exploration acreage. As demands for risk capital continued to increase, the scope of co-operation was also expanded to include Pertamina's fields and prime acreage's previously reserved for Pertamina. This has resulted in various types of contract Technical Assistance Contracts or TAC, and Enhanced Oil Recovery Contracts or EOR; Pertamina determines the type of contract applicable to a block or working area when offering it to other parties.

The TAC was first introduced in 1967. Under TAC, Pertamina surrendered the operations of Pertamina's producing fields or old shut-in fields to be rehabilitated. The main objective is to enhance production and exploitation of the existing petroleum reserves, as well as continuation of Pertamina production. The contractor uses its expertise and capital to improve production and takes a percentage from the incremental slice of production brought by his efforts. The term of contract initially varied between contracts, but in the mid 1970's they were modified to follow the form and term of Production Sharing Contract.

Production Sharing Contract JOA was first introduced in 1977. Under JOA, Pertamina and contractor have equal interests in the contract with the contractor as operator. This type of contract is used for exploration acreage previously operated or reserved for Pertamina's own development. In this system Pertamina holds a maximum 50% participating interest and the remaining is the contractor's participating interest. The term is subjected to the same terms as in the PSC. A further development of the Joint Operation Agreement is the delegation of operatorship to Joint Operating Body, an operating organisation that is staffed by Pertamina and Contractor's personnel and supervised by a Joint Operating Committee (JOC). The membership of the JOC constitutes of Pertamina and contractor. The JOC approves the work program and the budget and sets policies.

Introduced in late 1988, Enhanced Oil Recovery Contract (EOR) was introduced for the purpose of undertaking enhanced oil recovery projects within certain depleted fields that being operated by Pertamina through primary recovery methods. Pertamina and Contractor have equal interest in the contract, but Contractor will provide all funds required for pilot, development and operation with the operator is delegated to Joint Operating Body.

2.1.4.4. Risk Service Contract

Under the RSC system, the government retains ownership of petroleum resources, while the petroleum company explores at its sole risk as the contractor of the government. The government also supervises the operation. In the case of successful exploration all production will belong to government. The government allows the contractor to recover those costs through sale of the petroleum and pays the contractor a fee based on a percentage of the remaining revenues. This fee is also subjected to taxes. While in RSC, the contractor does not receive a share of production like in PSC, the terminology and arithmetic between PSC and RSC are quite similar, or the arithmetic that shapes out the contractor's revenues in RSC is in the same fashion as a PSC of sharing production.

The RSC system is extensively applied in Brazil. Under the Brazil's RSC system, the government still retained the ownership right of the resources and contractor bears the risks during the exploration and development. The contractor was required to provide a bank guarantee in the amount of exploration expenditures commitment. Geological data fee was payable at USD 250,000 to 500,000. The contract area was generally around 3,000 km2, while term of the contract varied from contract to contract. The size of remuneration and contract period were negotiated through bidding and then stated in the contract. Income tax was set at 25% of the net income (Gao, 1993: 476 - 489).

2.1.4.5. Comparison among Royalty and Tax, Production Sharing Contract and Risk Service Contract System

Dealing with the resources ownership aspect, from the petroleum companies' view, the most important advantage of RAT system is that it grants the owner something like to a type of real property. It provides good security to borrow money if the petroleum company needs to raise the finance for the operation and it can be mortgaged and can support easement and caveats. In contrast, the ownership of the resources in PSC and RSC still belong the government, therefore the PSC and RSC contractors do not have the advantage as in RAT system above. In recent years, the PSC contractors, particularly those based in the USA, can book the reserves in their balance sheets even though they do not own them. The rationale behind this is that the petroleum company is entitled to produce for a long period time. It can book the reserves because of access rather than legal title. Because of that PSC is attractive to petroleum companies (Bindemann, 1999: 85). But from the point of view government, the RSC and PSC are more attractive than RAT. In RAT system government cannot involve in the strategic decision-making and control the development of the resources, since the ownership belongs to the petroleum company.

Dealing with risk aspect, the risks during exploration phase in RAT, PSC and RSC are similar; they are borne by the contractor. While in development and production phases, in RAT system the petroleum company bears all those risks; while in PSC and RSC systems, they are shared between the contractors and the government.

The level of control of host government in PSC is medium, more than in RAT but less than in RSC system. RAT has the simplest arrangement in terms of form, content and administration, followed by RSC, while PSC has the most complex form. These two aspects make the RAT more attractive on the view of the petroleum company.

Cottee (1992:485-487) made a comparison between the PSC system applied in Timor Gap and RAT system in Australia. The RAT allows the producer of large field to reap more profit/high reward, due to its flat rate. In contrast, it could cause premature shut-in in marginal field, if costs tend to rise during the latter phase of production. This situation can be minimised through imposing a rate of return royalty. The RAT might make sub-economic production. For example, when the oil price is low, then the marginal field or sub-economic discovery should wait until the price increases (Cottee, 1992:484).

From the point of view of host government, the disadvantages of RAT system is that the royalty is flat which will not support in maximising the economic rent for the government. Another disadvantage is that the government is not involved in the operations and risks that could cause situation of unrealistic policies and regulations. From the company's perspective, as royalty could easily be changed, it could become disadvantage for the petroleum company. In politically stable country, such disadvantage is unlikely to occur thereby it is not a major concern. The royalty is payable from the first day of production, even before the development cost of the project has paid off, which would lead to the increase in the threshold rate of return required thereby discourage new investment (Cottee, 1992:484-485).

One of the advantages of PSC system on the host government view is that, with the authority of the ultimate approval and mine remain vested in host government, the PSC system can maximises the multiplier effect of development of the domestic industry; the PSC can have various preference provisions for its national product and services. The host government could also get maximum economic rent of any large discovery. The PSC system also allows disputes to be referred to some sort international arbitration; this at least allows a contractor to feel that the host government is not always both a judge and jury (Cottee, 1992:485-487).

On the other hand, one of disadvantages of PSC system is that it could encourage inefficiencies on costs since the petroleum company could reimburse all its operating cost. PSC also requires a relatively large bureaucratic and difficult administration, such as tender process, cost recovery monitoring and others. It is arguable the PSC system close to a nationalised industry, since this system has the high degree of government involvement and interference in a lot of essential management decisions in PSC system (Cottee, 1992:485-487).

The RSC as applied in Brazil appears similar to the PSC, but differs in certain important matters. The most basic is that the recovering of costs of contractor is in cash not in kind, it gives the contractor fewer rights in the service area, and it gives the government the possibility of asserting direct control over the development and production strategies (Gao, 1993: 493).

In analysing some RAT (in US, UK, Norway and Colombia) and PSC contracts systems (in Angola and Equador), Mannarino (1991: 172-173) made a conclusion that there is no overall *best contract* if considered only by its clauses, either for the host government or the petroleum company. In fact, the host countries have to model the petroleum contract dispositions in accordance with the exploration results. According to him, *the best contract* is the one yielding the petroleum company the opportunity of an overall compensation equivalent to other activities. It requires the host government to understand the geological risk associated with exploration activities. Moreover Cavoulacos (1986:4) had similar opinion as Mannarino: the petroleum contract is not just specific terms; it should be chosen based on individual country and project circumstances. He suggested having sliding scales in the contract form selected. The host governments should avoid the desire to over regulate and should select petroleum companies appropriate to the country's geological potential and overall circumstances.

2.2. The Indonesian Production Sharing Contract

2.2.1. The Development and the Role of the Petroleum Exploration and Production Industry in Indonesia

Since the first oil discovered in 1885, the role of petroleum business is important for the government, the Dutch Government (Dutch Governor General of Netherlands' East Indies) in the era of Dutch Colonial and then the Government of Indonesia (GOI) since the Indonesia's Independence Day in 1945. The following presentation describes briefly the development and the role of the petroleum E&P industry in Indonesia from it first discovered to 2003 period.

2.2.1.1. The period of Concessionary/Royalty and Tax and Contract of Work

Indonesia's petroleum E&P industry is one of the oldest in the world. It started more than a century ago (see Figure 2.6). Aeiko Janszoon Zijlker discovered the first sufficient commercial well at Telaga Said field in Langkat, East Coast of Sumatra in 1885. The year 1885 later was considered as the birth of Indonesia's petroleum industry. This was soon followed by discoveries at Ledok in East Java, Muara Enim in South Sumatra and Sanga-Sanga in East Kalimantan (Pertamina, 1994:6). These events then led to the establishment of the Koninklijke Nederlandsche Maatschappij tot Exploitatie van Petroleum-bronnen in Nederlandsch Indië (Royal Dutch Company) in 1890 by Zijlker and his friends.

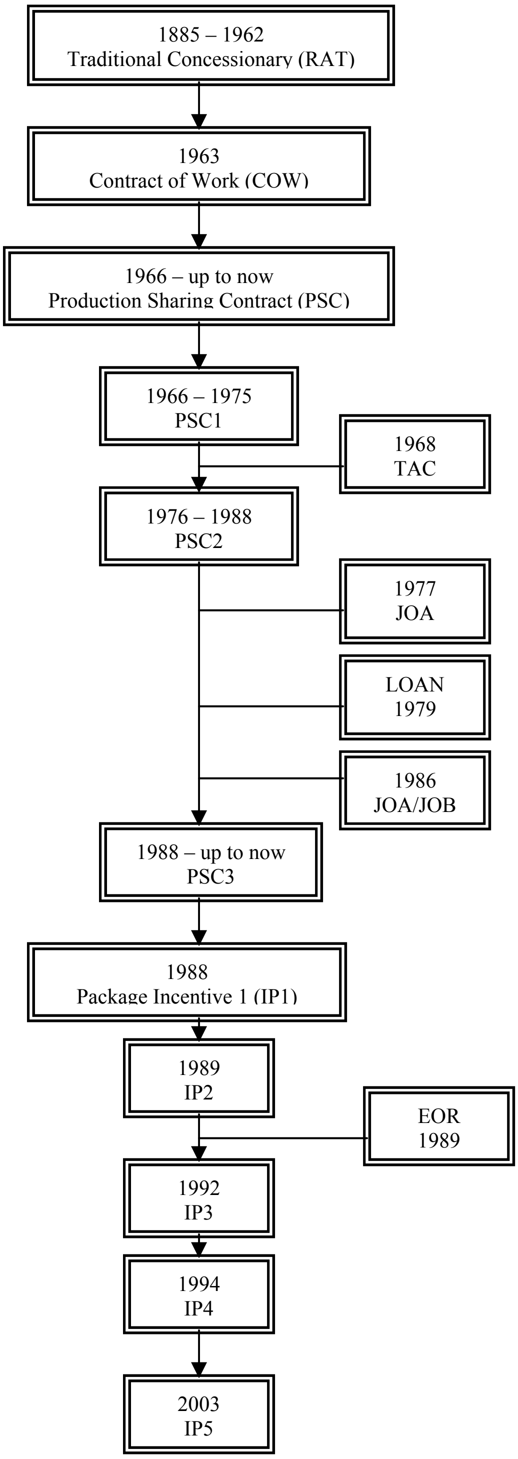


Figure 2.6: Indonesia's petroleum contract development 1885 – 2003 (Pertamina, 1997:16)

This company carried on all phases of petroleum business from production, refining to marketing crude oil. Their first refinery was built in 1892 and the first crude oil port was built in Pangkalan Susu in 1898. Adrian Stoop, the former employee of Zijlker, followed him building a petroleum company in Surabaya after he discovered oil reserves in Surabaya in 1887 and built oil refinery in Wonokromo, East Java and Cepu, Central Java in 1890. After that Shell Transport and Trading Company, a British company that had been drilling in East Kalimantan since 1891 and discovered oil reserves in 1894, built refinery in Balikpapan. Since then up to the end of nineteenth century, there were eighteen companies operating in Indonesia (Andel, 1961:75-80 and Pertamina, 1994:7-8).

In 1907 the Royal Dutch Company merged with the Shell Transport and Trading Company to form Royal Dutch Shell. Since then Royal Dutch Shell Group ran all the petroleum business in Indonesia and dominated colonial oil exploration for more than thirty years (Andel, 1961:75-80 and Pertamina, 1994:7-8). By 1911 Royal Dutch Shell operated concessions in Sumatra, Java, and Kalimantan, and Indonesian oil production was almost 4% of total world production. Later this company divided its activities into three subsidiary companies, i.e. Bataafssche Petroleum Maatschapij (BPM), Aziatic Petroleum and Saxon Petroleum company that each of them carried on production, marketing and oil transport. In east Java there was Dortshe Petroleum Company, but it was sold to BPM in 1911.

In 1912 an US Company built his subsidiary in Indonesia, named Nederlandsche Koloniale Petroleum Maatschapij (NKPM), later it changed to Standard Vacuum Petroleum Maatschapij (SVPM) and changed again in 1959 to Standard Vacuum Petroleum (Stanvac), who ran oil field in Talang Akar, Pendopo South Sumatra. In order to face the competitiveness of the US Company, BPM and English government with fifty-fifty shares, built a new petroleum company named N.V. Nederlandshe Indische Aardolie Mij (NIAM), which operated in Jambi and Bunyu Island, East Kalimantan and started its production in 1924.

In 1930, Standard of California built his subsidiary in Indonesia, named Nederlandshe Pacific Petroleum Maatschapij and in 1936 signed a new contract to explore oil in Rokan block. In the same year Standard of California built cooperation with Texas Company (Texaco) a new company, named California Texas Oil Company (Caltex) that got concession in along coast Central Sumatra and Pekanbaru and discovered oil in Minas structure in 1943. Although their production did not begin until the 1950s, the Duri and Minas oil fields became the Indonesia's most important oil fields, amounted to 50% of Indonesia's oil production. Later Caltex developed Minas as the largest oil field in the world after the Second World War (Andel, 1961:75-80 and Pertamina, 1994:7-8).

In the effort to expand its business, in 1935 BPM built 264 kilometres pipeline to transfer oil from Jambi field to the refinery location in Plaju. In the same year BPM with Shell and Stanvac built a new petroleum company that operated in Irian Jaya, named *De Nederlandsch Nieuw Guinea Petroleum Maatschapij (NNGPM)*. In 1935 NNGPM got concession near Sorong and its first production started in 1948 from Klamono field 4000 barrels per day. As a result Indonesia became the largest oil production country in the Far East with average oil production around 62 million barrels per year during 1939 – 1940 (Pertamina, 1994:7-8).

The earlier legislation in petroleum industry was the Dutch East Indies' Mining Law of 1899 and 1906, which was amended at various times. This Law constituted the legal basis for petroleum concessions issued by the colonial government to certain concessionaires, known as traditional concessionary/royalty and tax (RAT) system. The law separated the ownership of the land from the ownership of the subsoil petroleum resource. The petroleum resource wealth of the country was the property of the state. The explanatory memorandum of this law stated that it was the intention of the government to use the petroleum resource wealth of the Dutch East Indies as a source of revenue. The concession term ran up to 75 years, during these 75 years period the concession holder acquired right to explore and to produce the oil resources in an area of land defined as the concession and having direct control over these resources. For return of its right the concession holder obliged to pay a royalty of 4% and corporate tax to the colonial government (Andel, 1961:75-80 and Pertamina, 1994:7-8).

In 1918, the colonial government revised the regulations, making less favourable to petroleum companies. The petroleum company had an obligation to drill and to return those part of concession area that had no oil prospects. The company was further obliged to pay a profit tax amounting to as much as 20% of the net profit. Because they derived from Section 5A of the 1918 amendment to the law

1899, these concessions were historically known as 5A Contract/Agreement. The law amended again in 1929 that decreased the period of concession from 75 years to 40 years, higher requirement conditions such as to drill for the concession holder and others. The tougher amendment (less favourable to petroleum company) showed the Dutch Colonial's bargaining position increased. The RAT system dominated the oil scene in Indonesia and remained valid until 1960, but was not operative during the period 1942-1945 because of the Japanese wartime occupation of the colony.

With the Japanese attack on the Dutch East Indies in 1942 demolition squads destroyed many important oil installations. To get them rebuilt after the War the Dutch East Indies Government adopted let alone policy that exempted reconstruction fund from foreign exchange and customs controls. Under this agreement, foreign companies could retain all earnings from oil sales as long as they agreed to provide from their own overseas sources the necessary fund required to restore their production facilities and oil fields. The Dutch East Indies Government got some foreign exchange out of the oil especially by selling to the companies the local currency for taxes, royalties, etc. The let alone agreement was continued by Indonesia after its independence in1945 until 1960. This agreement simply allowed the 5A contract to remain in effect until the introduction of a new legislation.

In 1945 Indonesia proclaimed his independence and nationalistic feelings were running high, the government increased its control over the oil sector during the 1950s and 1960s. The concessions were regarded as being far too generous to foreign companies at the expenses of the country. The GOI froze all the concessions as the responses. This action made stagnation in petroleum development, and it was disadvantageous for both, the GOI and the foreign petroleum companies. Since the war much had changed and with the transfer of sovereignty on December 27, 1949 the petroleum companies lost their political influence. However, their production costs, prices and distribution policy were kept secret and the GOI never got a clear picture of the situation (Andel, 1961:75-80).

A new episode in the Indonesian petroleum industry was started with the birth of the Indonesian Law Number 44 prp of 1960, the Mining of Mineral Oil and Gas, which was signed by President Sukarno on October 26, 1960. It changed the legal working status of the foreign petroleum companies and practically nullified their investments. The most important change was the declaration that the mining of oil and gas should only be undertaken by the state and exclusively carried out by national petroleum company. The concession had officially come to an end and converted into Contract of Work (COW, in Bahasa Indonesia: *Perjanjian Karya* or *Kontrak Karya*). With this Law, the petroleum companies were named as contractors to the national petroleum company. Three national petroleum companies were thus established and authorized by the GOI to develop and exploit the mineral resources; they were Permina, Pertamin and Permigan. Later in 1966 GOI dissolved Permigan, and in 1968 Permina and Pertamin were merged into one company, Pertamina, in order to raise the efficiency of the operation of petroleum industries in Indonesia.

The term COW was employed to describe a type of arrangement under which the foreign petroleum company was a contractor to the GOI, and the term concession had been replaced with authority to mine in deference to the nationalistic demand that mining rights be vested in national oil companies. The COW contract was approved by the government, and was ratified by the parliament and had the force of law. The management of the operation was still in the responsibility of the petroleum company.

The contract's duration was 20 years for the extension of concession contract. While for new contract, contractor was obliged to pay 5 million USD as signing bonus and the duration of contract was 30 years. The net profit was shared 60% for the GOI (inclusive contractor's taxes) and 40% for the contractor. And 20% of total revenues were reserved as a minimum GOI income out of the COW. The contractor obliged to deliver 25% of their share to the GOI as DMO at a reimbursed of 0.20 USD fee per barrel. Contractor owned all physical assets acquired for the operation.

The foreign petroleum companies valued the law as unattractive, as a result Indonesian oil production reduced to only about 2% of the total world output, and in the world market the value of its oil available for export was practically negligible, even though it represented about 222 million USD or 24% of the total exports of Indonesia. On the other hand, the government was completely dependent on oil as a source of state revenue, both in local currency and in foreign exchange, that they were reluctant to risk the experiment (Andel, 1961:75-80).

Three COW contracts were signed in 1963, Caltex as the contractor to Permigan, Stanvac as the contractor to Permina, and Caltex as the contractor of Pertamin (Pertamina, 1994:31-32). Although the COW contracts were seen better than RAT contract, but Ibnu Sutowo, the President Director of Permina valued COW as similar to RAT system, since the management was still the responsibility of the petroleum company. Therefore, he introduced a new petroleum contract system, the PSC system in the mid 1960s. Now COW is no longer employed in Indonesia, the last two COWs were expired in 1993.

According to Gao (1993:153-154), three relevant points were suggested as the significance of the COW. First, these systems helped to prevent a precipitous withdrawal of the remaining foreign investment from Indonesia; second, they provided the Indonesia’s petroleum administrators at that time with the opportunity to educate themselves about the industry; and third, the most important, the COW gave birth to the PSCs.

In 1962 Indonesia joined Organization of Petroleum Exporting Countries (OPEC) as an active member. OPEC member countries meet at least twice a year to coordinate their production policies in light of market fundamental, in an effort to control oil price volatility and to counter what they see as softening crude oil prices.

2.2.1.2. The Production Sharing Contract First Generation

Actually agreements similar to the idea of PSC system were already signed in Indonesia, first between Permina and the Kobayashi group in 1960, followed by Refican and Asamera in 1961. But it is generally agreed that the IIAPCO contract of 1966 between an *independent* petroleum company named IIAPCO and Permina, covering a block in western part of Java Sea was the first genuine PSC in petroleum industry. The PSC basic principles agreement in the IIAPCO contract called the First

Generation of PSC (PSC1) would then become the standard principles for PSC system until now.

At first the *major* petroleum companies were not eager on PSC system, they were unwilling to invest capital into venture in which they were not allowed to own or even to manage. However, later they accepted the PSC system, because they were worried about loosing too much territory to the *independents*. (Bindemann, 1999:68).

The IIAPCO experience opened the gate to mushrooming PSCs (Gao, 1999:165). Moreover Machmud (2000:53) said that IIAPCO and its successors, Sinclair and ARCO, also are worthy of having pioneered the Indonesian offshore operations. They were the first to operate offshore in Indonesia.

In PSC1 agreement (see Table 2.1) GOI is the owner of the petroleum resources. The duration of the contract was 30 years, including 6 to 10 years exploration period. Pertamina on behalf of the GOI was responsible for the management of the operations. The contractor was responsible for the preparation and execution of work program as specified in the contract. If commercial oil discovery were not made by the end of the exploration period, the contract would be automatically terminated. All risks occurred during exploration phase were borne by the contractor only. In case of commercial discovery, all expenditures would be recovered through cost recovery mechanism. The cost recovery would be limited to 40% of the annual production. Contract was based on production sharing not profit sharing; hence the remaining oil after cost recovery deduction was shared between the Permina on behalf of GOI and contractor with production-sharing split of 65/35 (65% for the GOI inclusive of all contractors' taxes and 35% for the contractor). This production-sharing split became 67.5/32.5 for production above 75,000 BOPD. The contractor was free to export its entitlement under the cost recovery. The purchased equipments became the property of GOI. The contractor was obligated to supply out of its share each year, 25 % of production times its share percentage to the domestic market obligation (DMO) at price of 0.20 USD per barrel. These terms represented a very simple system and guaranteed a minimum 49% of production for Indonesia annually (Anwar *et.al*, 1989:4).

A special body called *Dinas Koordinasi Kontraktor Asing* (DKKA) initially been created by P.N. Permina in the late 1960s, later its name was changed to *Badan Koordinasi Kontraktor Asing* (BKKA) in the late 1970s by Pertamina (the resulting company from the merger of Permina and Pertamin in 1968). Later it was changed again to *Badan Pembinaan Pengusahaan Kontraktor Asing* (BPPKA) in the late 1980. It functioned as a coordinating body reporting directly to the President Director of Pertamina. According to Machmud (2000: 54) in the beginning control exercised was not tough, but after 1976 became pervasive to the extreme. Later on, in 2002 by the Oil and Gas Law Number 22 of 2001, it was changed again to *Badan Pelaksana Kegiatan Usaha Hulu Minyak dan Gas Bumi* (BP Migas) under the Ministry of Energy and Mineral Resources.

The de facto expansion of the state was sustained by a general policy shift to justify greater GOI intervention in the economy. Sukarno's Guided Economy was initiated in a new eight-year development plan begun in 1959, which entailed a twelve-fold increase in government project expenditure from the previous plan, without clear sources of finance. By the mid-1960s, central bank credit to the government accounted for half of government expenditures. This deficit spending led in turn to mounting inflation, which peaked at 1,500% between June 1965 and June 1966. At the same time, foreign debt mounted, both from the West and increasingly from the Soviet Union. The economy stagnated and by 1966 per capita production was below the 1958 level (US Library Congress, 1998). Steady flows of investment capital were needed in all sectors to rehabilitate the economy.

The PSC1 system was successful to increase the GOI revenues and to rehabilitate the Indonesia's economy. Annual Indonesia's oil production increased three times from 1966 production to its peaked in 1977 at over 600 million barrels. And a year later in 1977, Indonesia started its role as supplier of LNG when the facility in Bontang, East Kalimantan was opened and followed by the second plant in Arun, North Sumatra (Machmud, 2000:56). Table 2.2 shows that during nine-year period (1966-1975), 59 PSC1 contracts were signed. Compared to other PSC systems, PSC1 had the highest number of producing contract, 18 PSC1 contracts or 56% out of total producing PSC contracts during 1966 – 2003. While the other 41 PSC1 contracts were already terminated in 2003. Moreover exploration activities increased from 17 wells in 1967 reaching several peaks with the highest 212 wells in 1974. Since the oil price increases of 1970's, the petroleum sector has become a significant contributor to the economy. As late as 1980's oil and gas was still the biggest single export commodity, contributing to about 49% of the Indonesia's export earnings (US Embassy, 2004:1).

Table 2.1: Development of the Indonesian PSC system 1966 – 2003 (Anwar *et al*, 1989: 3-8 and Pertamina, 2000: 9 –15)

No	Term	PSC1 (1966 – 1975)	PSC2 (1976 - 1988)	PSC3 (1988 – recent)
1	Investment Credit	-	For new field: 20% of capital expenditures for production facilities.	The IC will henceforth be given regardless the condition the Indonesia income out of the development project not be less than 49 % of the project revenues
2	Commerciality	-	Minimum guarantee 49 % of the gross revenue for GOI	Abolished
3	Domestic Market Obligation - Quantity - Price holiday - Price	 25 % of con.profit share - - 0.20 USD/B	 25 % of con.profit share 5 years with export price 0.20 USD/B (after 5 years)	 25 % of con.profit share 5 years/60 months As stated in each IP
4	First Tranche Petroleum	No	No	20 % of production shared GOI and contractor as production sharing split
5	Cost Recovery	A cost recovery limit of 40% of total revenues	No limit	No limit
6	Depreciation of Capital Expenditures	-	7 years DDLB	5 years DDLB
7	Oil Production Sharing Split, GOI : Contractor	65/35 (inclusive taxes) 67.5//32.5 (inclusive taxes) for production over 75,000 BOPD.	85/15	As stated in each Incentive Package
8	Gas Production Sharing Split, GOI : Contractor	-	70/30	As stated in each Incentive Package
9	Tax	Inclusive in production sharing split	*Before 1984* 56 % (45 % Income + 20% Dividend Tax). *Since 1984* : 48% (35% Income + 20% Dividend Tax)	48 %
10	Others			Deregulations of procedures for procurement of materials and services by contractor

Following the downfall of Sukarno, the New Order regime under Suharto pursued, with financial assistance from the International Monetary Fund (IMF), a variety of emergency stabilization measures to put the economy back on course. The

New Order remained committed to a stable economic environment encouraged by responsible fiscal and monetary policy, but concerned over foreign economic dominance, the limited national industrial base, and the need for *pribumi* economic development mandated increased government regulation during the 1970s. In spite of these increasing government controls, the economy continued to prosper throughout the 1970s, with GDP growing an average 8% annually (US Library Congress, 1998).

Table 2.2: PSC contracts signed in Indonesia 1966 – 2003 (Pertamina, 2000:11, US Embassy, 2004:app.3, BP Migas, 2004)

Period	Time Frame	Total Contract	% Total 1966 - 2003	Producing Contract	Success Ratio by each type	Success Ratio total.prod.con.	Non-Prod. Act. Contract	Terminate Contract
PSC1	1966 - 1975	59	25%	18	29%	56%	0	41
PSC2	1976 - 1988	64	23%	8	13%	25%	3	53
PSC3+IP1	1988 - 1989	5	2%	0	0%	0%	0	5
PSC3+IP2	1989 - 1992	33	13%	3	9%	9%	5	25
PSC3+IP3	1992 - 1993	10	4%	3	30%	9%	5	2
PSC3+IP4	1994 - 2002	70	27%	0	0%	0%	44	26
PSC3+IP5	2003	16	6%	0	0%	0%	16	0
PSC3+all IP	1988 - now	134	52%	6	4%	19%	70	58
Total	1966 - 2003	257	100%	32	12%	100%	73	152

The PSC1 system worked well until mid-1970s. Law No. 8 of 1971 determined once and for all that in the petroleum sector only PSC type contracts were available foreign investors, and that there was no room for COW. The COW signed prior to the promulgation of Law No.8 of 1971 remained in full force and in effect, and upon the contract's expire date, they would have to be converted into PSC. This law also created a monopoly by establishing Pertamina as the sole agency for petroleum activities, both upstream and downstream (Machmud, 2000:57-58).

When crude oil price increased significantly from 3.69 USD per barrel in 1973 to 10.57 USD per barrel in 1974, it created windfall profit. GOI argued, the windfall profit should not only benefit the contractor, but should give benefit to the GOI too. As a result, windfall agreement was signed in 1974; whereby up to a price of 5 USD per barrel in revenues from crude oil sales, the sharing split was to be held at 35/65 (inclusive of taxes). While if oil price rose in excess of that base price, the sharing split would shift to 15/85 in favour of Pertamina. The base price was to be adjusted periodically, following the rise and fall of the UN Commodity Index. At the same time negotiations were started about DMO price, due to the low DMO price (only 0.20 USD/barrel). As a result the number of contract signed decreased to the lower of only one contract signed in 1974.

In 1975 another event occurred, a new ruling of taxes was issued by the tax agency in home country of the majority of the contractors operating in Indonesia, which did not allow tax credits for corporate taxes paid in Indonesia. This situation brought about major changes to the PSC terms leading to new generation of PSC system, named PSC2.

2.2.1.3. The Production Sharing Contract Second Generation and the Variation of the Production Sharing Contract

The basic principles of the PSC2 were similar to the PSC1, with some modifications (see Table 2.2). In PSC2, no cost recovery limit was applied and cost recovery was based on generally acceptable accounting principles. Capital expenditures were allowed be depreciated over 7 years double declining balance, and non-capital cost including intangibles might be expensed. Under the PSC2, in the initial years, revenue could be claimed all for the expenditures as cost recovery. GOI only started to receive a share of production whenever all costs had been recovered, something normally occurred only after several years of production. This contract looks reasonable in the economic perspective, given the continuing rise in oil price.

In addition, the production-sharing split was changed to 15/85 for oil and 30/70 for natural gas in favour of GOI, because gas development took longer lead times and required larger front-end investment. Contractor's share was subjected to corporate income tax of 56% (45% income tax and 20% of the balance as dividend tax). The new Tax Law of 1984 changed the tax rate from 56%to 48%.

Unfortunately, the reaction of the petroleum company to these contract changes was not favourable, the number of exploration and contracts signed still decreased to the second lowest peak. No contract was signed in 1976. The strong oil price at that time saved the industry. Prices continued to soar in 1981, reaching 35 USD per barrel, and oil exports peaked at 15 billion USD, or about 70% of total export earnings. In 1982, however, production declined, reaching a low of 460 million barrels and the oil market began to weaken that same year, when Indonesia's Minas crude was priced at 29 USD.

To get exploration going again, then GOI issued two extra incentives. The first was the investment credit incentive, amounting to an additional allowance for cost recovery of 20% of asset value for direct production facilities, applicable only to a new field, taken out of gross production in the earliest production year and subject to GOI getting 49% of production over the life of the field. The second was better pricing structure for DMO whereby for the first 5 year (DMO price holiday) of commercial production from new field, the contractor received a price per barrel equal to the export price. After that the DMO price then going down to 0.20 USD per barrel.

In 1980 GOI issued Presidential Decree No 10 of 1980 and No 14A of 1980, which were initially intended for use in the government institution for procurement of goods and services. This decree stated that procurement of goods exceeding 500 millions IDR shall be approved by a procurement team and applicable for state owned company, including Pertamina and the PSC contractors. The GOI justified its policy of applying the Presidential Decree 14A of 1980 in the PSC on the ground for national development and promotion of domestic product and services (Hasan, 2001:26).

In general contractors did not object to promoting the use of domestic products and services as the implementation of Presidential Decree No 14A of 1980, but more to the procedures they have to follow. According to them, the procedure implementing the decree particularly the layers of approvals and sequences of negotiations for lower prices had contributed to substantial delays in the award of contracts, which in turn affected execution of work program (Hasan, 2001:26). These problems ran for a long time, until in 2000 the GOI responded by revising the delegation of authority and raising the permissible level of expenditure of PSC for procurement of goods and services and streamlining the process for soliciting the approvals by issuing Presidential Decree No 16 of 1994 and No 8 of 2000.

Moreover, by the implementation of Presidential Decree 14A of 1980 in such situation, GOI seemed to have treated the contractors as one of the governmental unit and placed Pertamina above the contractors. It was opposite with the initial provision as stated by Ibnu Sutowo when he introduced the first PSC, which stated that the management of the operations in the cooperation contract was a parallel relationship within the context of cooperation contract and coordination (Hasan, 2005:94). In contrast, in the Malaysian PSC, for the utilisation of domestic products, Petronas (states own petroleum company) published the procedure and regulation agreeable to the parties (Machmud, 1999:96-97). While China set up procedure for procurement of good and services including preferential treatment for domestic products by standardisation of local content (Kinney, 1994: 231-239).

Other issue was on value added tax (VAT or PPN *in bahasa Indonesia, Pajak Pertambahan Nilai*). In 1983 the GOI issued Law No. 1983 on value added taxes on goods and services and sales taxes on luxury items (PPN 1984) that was effective starting at 1 January 1985 and had been amended two times, in 1994 by law No.8 of 1993 and by Law No. 18 of 2000. Petroleum activities under the PSC were not subject to VAT. Drilling activity was not an object for VAT, while for non-producing active PSC; the VAT payment was deferred until the commencement of production (Kartadinata, 1991). The issue was on the mechanism and the long time required to refunding VAT that had been paid. The VAT refund should not be more than 60 days, but in reality it took several months that also indication of lack coordination between institutions. According to IPA (2004) the impact in the long term was to increase the need of additional working capital and to reduce the interest of investor for investment.

The success of the PSC2 contract was below that of the PSC1. There were 64 PSC2 contracts signed during 1976 – 1988, in which only 8 contracts were successful in producing oil and gas, 3 contracts were still active in 2003 but not producing, and the remaining 53 contracts failed and were terminated. The 49% rule was highly unpopular and was later mistakenly used as threshold for commerciality, whereas it was only intended for the investment credit incentive.

As demands for risk capital continued to increase, to attract investment in Pertamina own field operations, GOI had introduced some variants of the PSC system involving Technical Assistance Contract (TAC), Joint Operating Agreement run by a Joint Operating Body (JOA/JOB), and Enhanced Oil Recovery (EOR), which came into being in 1980s, except two TAC contracts in 1968.

Table 2.3 shows that in total 41 TAC contracts were signed up to 2003, in which 9 were producing oil, 28 were non-producing active, while 4 were already terminated in 2003. Only 2 contracts executed exploration and production operation and coordinated by BP Migas. The other 39 TAC contracts only rehabilitated Pertamina's old fields and were coordinated by Pertamina. Nearly all TAC contracts (except 2 contracts) had transferred their stakes to foreign companies and 65% of them were not active, due to financing difficulty or reluctance to take risks (Hasan, 2001:30).

Table 2.3: Indonesia's Petroleum Contracts signed 1966-2003 (Pertamina, 2000:11, US Embassy, 2004:app.3, BP Migas, 2004)

Contract Type	Total Contract	Producing		Non Producing Active		Terminate	
		Total	%	Total	%	Total	%
PSC	257	32	9%	73	21%	152	44%
JOA	6	1	0%	1	0%	4	1%
JOB	33	7	2%	9	3%	17	5%
TAC	41	9*	3%	28	8%	4	1%
EOR	8	6	2%	2	1%	0	0%
Other	2	0	0%	2	1%	0	0%
Total	347	55	16%	115	33%	177	51%

* *2 coordinated by BP MIGAS, 7 by Pertamina*

Thirty-three JOB contracts were signed during 1977-2003 period, in which 7 were producing, 9 were non-producing and 17 were already terminated. While during the same period, 6 JOA contracts were signed, in which one was producing, one was non-producing active, while 4 contracts were already terminated. Only 8 EOR contracts were signed during 1978 – 2003, in which 6 were producing and 2 were non-producing active.

2.2.1.4. The Production Sharing Contract Third Generation and the Incentive Packages

The worldwide economic had slowed down starting in the early 1980's, followed by world recession during 1986 to 1987, which made consumers' effective conservation and diversification. The oil market gradually turned into buyers' market and oil price started decreasing. An unexpected event happened, fundamental elements of the petroleum industry started to weaken as oil prices dropped in 1986 to below 20 USD, consequently the number of contract's signed dropped to only 4 and the number of exploration sharply decreased to 82 wells that year.

In addition to the difficult situation above, Pertamina and contractor also faced problems; the commerciality criteria of the new field in the view of Pertamina in which the economics should secure GOIa income of no less than 49% of revenues (includes contractor's taxes). This condition created a problem in application to the development of marginal field (Anwar, *et.al*, 1989: 5-6).

The fall of oil price became problems for both parties. Indonesia suffered most, not only that its petroleum revenues were cut in half, but also in fields that already in tail-end period, it hardly got any share oil left, since all revenues were only enough to recover the expenditures. Hence the spirit of production sharing became diluted. The tail-end contractors were applying for 20 years extension to allow sufficient time for recovery of investment and profits from results of continued exploration or from activity secondary recovery project. Both parties were willing to renew the PSC system; especially since the government needed to secure its revenues during tail-end production period (Anwar *et.al*, 1989: 5-6).

As the revenues from petroleum industry were expected to continue to play as the primary income for Indonesia, in securing GOI's income and to accommodate the forthcoming extension of PSC, GOI introduced the Third Generation of PSC (PSC3) in 1988.

The PSC3 showed increasing flexibility. A new term was introduced, First Tranche Petroleum (FTP). FTP is a volume of 20% of gross production, firstly taken up before the cost recovery of expenditures, and it was shared between parties with the same production-sharing split and subject to tax. The objective of FTP was to secure the GOI income in the first production period. The FTP became the basic feature of the PSC3, and it was perceived as solving the issue of the commerciality criteria. Contractor argued the FTP was like a royalty payment.

Additionally, the change of the market from a sellers market to buyers market made uncertainty higher, the investment for petroleum E&P activities dried up. The drop in petroleum business in Indonesia had caused GOI to introduce incentive packages that were issued in 1988, 1989, 1992, 1994 and 2003; in this study they were named IP1, IP2, IP3, IP4 and IP5. The development of the incentives packages can be seen in Table 2.5. The trend in those following incentive packages reflected the increasing importance of the petroleum E&P activities in frontier areas and deep water.

The First Incentive Package (IP1) was introduced in August 1988 (see Table 2.5). The investment credit incentive of 17 % (20% according to old Tax Law) was applied to both oil and gas in new development without any conditions. In addition after the 5 years DMO price holiday, the DMO price of new field was set at 10% of the export price, but in the old field it was still set at 0.20 USD per barrel. The IP1 included deregulation measures to be taken in the procurement procedure.

Due to higher geological risks and infrastructure remoteness in frontier areas, the IP1 improved the production sharing split in these areas. The sharing split for production up to 50 MBOPD was 80/20; 85/15 for production 50 – 150 MBOPD; and 90/10 for over 150 MBOPD. For gas, production sharing split was still kept at 70/30 after tax in favour of GOI. Only five PSC3+IP1 contracts were signed in 1988, and all of them failed and were terminated.

Table 2.4: Development of Incentive Packages 1966 – 2003 (Anwar, *et al*, 1989:9-10; Pertamina, 2000:9 –15 and Petrominer, 2004:10-14)

Term	IP1 (1988)	IP2 (1989)	IP3 (1992)	IP4 * (1993)	IP5 (2003)
Investment Credit (IC)	17 % (20% according to old Tax Law)	For deep sea areas over 600 ft.: ▪ Oil = 110 % ▪ Gas = 55 %	Pre-Tertiary : 110% Water depth for oil gas - 200-1500m : 110% - > 1500m : 125%	No longer applied	Up to 110 %
Commerciality	Abolished	Abolished	Abolished	Abolished	Abolished
DMO: - Quantity - Holiday Price - Price (after first five years)	25 % share prod. 5 years (60month) 10% export price	25 % share prod. 5 years (60month) 10% export price	25 % share prod 5 years (60month) 15% export price.	25 % share prod. 5 years (60month) 25% export price	25 % share prod. 5 years (60month) 25% export price (mar), conv.15%
FTP	20 % prod. shared	20 % prod. shared	20 % prod. shared	15 % prod. shared	10%t all for GOI
Cost Recovery	No limit	No limit	No limit	No limit	No limit
Depreciation Capex	DDLB Capex	DDLB Capex: For gas field having reserves>7ys 100% assets useful life having reserves<7ys 50% assets useful life	DDLB Capex 50% assets useful life	DDLB Capex.	DDLB Capex.
Oil Production Sharing Split: GOI/Contractor	Conventional Old field = 85/15 New field = 85/15 Frontier < 50 MBOD = 80/20 150 MBOD = 85/15 > 150MBOD= 90/10	Conventional Old field = 85/15 New field, Marginal fields EOR = 80/20 Frontier Marginal fields and EOR = 75/25 Pre-Tertiary and deep sea > 1500m <50 MBOD= 80/20 150 MBOD= 85/15 >150MBOD=90/10	Frontier: 80/20 Frontier water depth > 1500m 75/25	Frontier and water depth > 1500m 65/35	Ranging from 80/20 to 65/35 according to geological and geographic conditions
Gas Production Sharing Split GOI/Contractor	Conventional 70/30 Frontiers & water depth: 70/30	no change	Conventional old contract : 70/30 new contract: 65/35 water depth>1500m 60/40 Frontier water depth >1500m 55/45	Frontier and water depth > 1500m: 60/40	Ranging from 60/40 to 55/45
Tax	48 %	48 %	48 %	48 % since 1997: 44 % (30% income and 20% div.tax)	44 %
Deregulation procurements and procedures	Further simplication in line with the deregulation policy				
Extension to the 6 years explor.	2 x 2 years	1 x 4 years			
Gas pricing	Not always oriented toward the gas field development econ.	Will be oriented toward the gas field development econ.			
Access to data	In the context of acreage to be tendered/bidding	Data acquired from surveys conducted by Pertamina will be available to prospective PSC contractors			

**) for Eastern Indonesia areas and part of Western Indonesia having similar geological and geographic conditions*

At that time most of the exploration activities were carried out in conventional producing areas located in western part of Indonesia. GOI thought a better share for contractor in frontier areas would provide the right motivation to attract the petroleum company to explore in these areas. For that reason GOI issued the Second Incentive Package (IP2*)* in February 1989 (Table 2.4), it addressed the production split for marginal fields, oil produced from pre-tertiary reservoir rocks, tertiary EOR projects, and the investment credit incentives for deep-sea areas.

The investment credit was increased to 110% for oil and 55% for gas for both the extended and new contracts that operate in standard, frontier and deepwater areas (deepwater being over 1500 m). While the DMO price for existing contract was changed to 10% of export price.

After tax oil production sharing split for marginal field (marginal field is defined as a field that its average production within the first two year is up to 10 MBOPD) was set up at 80/20 for new conventional areas and at 75/25 for frontier areas. While the after tax oil sharing split for EOR projects was changed at existing fields to 80 /20 for old and new PSC in conventional areas, and to 75/25 for frontier areas. Specifically for oil production from pre-tertiary reservoir rock, both existing and new conventional field, the after tax oil production sharing split was changed based on the volume of production (sliding scale). It was 80/20 for production up to 50 MBOPD, 85/15 for production between 50 – 150 MBOPD, and 90/10 for production more than 150 MBOPD. While for frontier and deepwater, the after tax oil split was changed to 75/25 for production up to 50 MBOPD, 80/20 for production between 50 – 150 MBOPD, and 90/10 for more than 150 MBOPD production.

The extension of the 6 years exploration period was changed to 1 x 4 years. The gas pricing will be oriented towards field development economics for new project and the access data will not be restricted only to contract areas open for bidding. The PSC3+IP2 increased the number contracts signed, 15 contracts in 1990 and 16 contracts in 1991; but in 1992 the number of contracts signed dropped again.

The Third Incentives Package (IP3) was introduced in August 1992; it placed more emphasis to stimulate activities in gas exploration and development in both conventional and frontier areas with better production sharing split and the improvement in investment credit and DMO.

At that time natural gas played an increasing role in Indonesia and would continue in the future. Therefore better production sharing split for gas was issued. The after tax gas production sharing split was changed to 60/40 for new frontier and to 65/35 for new conventional areas. For water depth in excess of 1,500 m, the production split went to 55/45 for new frontier and to 60/40 for existing PSC. And the after tax oil split specifically for new frontier areas was changed to single production sharing split (no sliding scale) of 80/20, and for depth water in excess of 1,500 m to 75/25. While investment credit were increased to 110% for gas and oil development in pre-tertiary reservoir, conventional as well as frontier and deepwater; whereas for water depths in excess of 1,500 meters the incentive went to 125%.

To maintain production level at 1 MMBOPD and to delay net oil imports until at least 2010, GOI knew that the E&P activity in high risk and remote areas should be encouraged. Hence, the Fourth Incentives Package (IP4*)* was issued in late 1993 and became effective in January 1994. The IP4 was based on geological reasoning with geographical consideration. The purpose of this incentive was to encourage the petroleum E&P in the frontier areas in eastern part of Indonesia and part of western part of Indonesia that had similar geographic condition.

The IP4 provided a really meaningful effort towards simplification. The production split for oil in frontier areas became 65/35 and for gas it became 60/40. The DMO price after 5 years holiday went to 25% of the export price. The FTP was reduced to 15%. There was only one water depth cut-off (at 200 meters), and no distinction was made between reservoir rock ages. Investment credit was no longer applied, and commerciality was abolished. Further adjustment was made in 1997, decreasing the tax rate to 44% (30% income tax and 20% dividend tax).

The IP4 came into effect in 1994. As a result of the application of the IP4, 70 contracts were signed during 1994 – 2002 period, the highest compared to three other incentive packages. Although the number of contracts signed increased, the oil and gas production had not increase yet. In 2003 (10 years after IP4's application) all 70 contracts had not produced oil and gas; 44 contracts were still active in exploration activities while 26 were already terminated.

The highest number of PSC3+IP4 contracts signed was 29 contracts in 1997 and it was the highest of petroleum contracts signed during 1966-2003. But after that, though the oil price increased, the uncertainties resulted in diminishing level of new investment; only four contracts were signed in 1999, five in 2000, increased to 11 in 2001 and decreased again to only one in 2002.

The IP4 had the longest application time than other incentive packages, from 1994 to 2003 before the issuing of the new incentive package 5 (IP5). During that 10 years period, Indonesia faced many problems and issues that influenced the petroleum E&P activities. Some of them are as follows.

The consequences of Indonesia joining the 21st century in terms of international trade put greater pressure on the GOI to become market oriented. Investors needed greater transparency and deregulation. Worse situation occurred, the country economic collapsed deeply in 1997. This financial crisis revealed a number of unseen weaknesses in the economy such as a weak financial system with lack of transparency, unprofitable investment in real estate, and shortcoming in the legal system (Touwen, 2003:8). GOI was forced to turn to the International Monetary Fund (IMF) for an emergency debt-relief package totalling to $43 billion. This situation made the financial strength of Indonesia decreased drastically. The IMF recommended Indonesia to implement an economic reform program in order to help to save its economy that included creating greater transparency and stricter enforcement of laws and regulations in the area of government procurement.

In the same year a shock political change also occurred. The Indonesia's people power forced the GOI to do political reformation process and Suharto was forced out from office and was replaced by B.J.Habibie as president of Indonesia in May 1998. Political changes rapidly evolved; B.J.Habibie initiated a genuine democratic process for choosing a parliament and a president in the June 1999 election. The full Parliament then elected Abdurrahman Wahid as president and Megawati as vice president. Wahid was accused of incompetence and impeached in July 2001 and replaced by Megawati. During her presidential time, democratic, peaceful and smooth Indonesia's parliamentary elections as well as the first and second rounds of presidential elections were successfully conducted in April, July and September 2004. As a result, Susilo Bambang Yudhoyono replaced her as President in October 2004. The new government and parliament give strong promising positive points on business investment climate in Indonesia.

Other issues arose, the majority of companies participated in bidding round and the winners were domestic companies and newcomers. This situation indicated the increasing interest of domestic investors and the declining interest of foreign investors to invest risk capital in Indonesia. The trend of declining interest can also be seen in the increasing number of foreign oil companies transferring their Indonesia's contract, opening up opportunities for domestic company to take over. In general, the foreign oil contractors had been focusing their operation to improve the production and cash flow from existing assets and were not set to make large and risky investment (Hasan, 2005: 72 - 73).

As part of implementation of the reformation process in Indonesia and enhancing national unity, in 1999 the GOI promulgated the Law No 22 of 1999 and No 25 of 1999. The Law No 22 of 1999 provided the provincial government with greater authority to manage their internal affairs, except in certain areas such as national security, foreign policy, fiscal and monetary policy, justice system, religious affair, strategic policy and national planning. According to this law regional governments have the authority to approve investments in all areas except oil and gas, which remained under jurisdiction of central government. While petroleum operations are still within the jurisdiction of central government, the local government now controlled many of supporting activities. They could issue regulations and permits that in the past were issued by the Directorate General of Oil and Gas, such as issues for construction services, utilisation of contract area for other non-petroleum activity, waste petroleum products, environmental control and others. The law on local taxation give local governments the right to impose new taxes and levies within certain limits.

The Law No 25 of 1999 addressed the sharing or allocation of revenue between the central and regional governments. Under the law the revenue from oil and gas would be shared 85/15 and 70/30 between the central and regional government respectively. Of the 15% of the oil revenue flowing to the region, six percent would go to the district where the petroleum operation was located, six percent would be shared among the other districts in the province, and the remaining three percent would go to the provincial government. Similar sharing ratio is applied to gas revenue.

These new legislations recognised political reality. Indonesian citizen in different parts of the country want greater involvement in the management of their day-to-day affairs. This is a common aspiration around the globe. There are considerable opportunities in the process. The expectation is that there will be an enhanced local provision of public goods, tailored to local preferences and considerations. This should create greater prosperity for all Indonesian citizens, in the context of enhanced economic activity across Indonesia. International experience suggested that ill-sequenced reforms could vitiate the objectives and advantages of the decentralization process. The danger is that effective service delivery can be threatened even in places where the state presently provides such services, that there can be a capture by local interests threatening good governance, and that Indonesia hard-earned stabilization might be jeopardized (Ahmad and Hofman, 2000).

Since it was introduced in January 1, 2001 there had been uncertainty over details of the implementation of regulations. The regional or local government seemed to have little knowledge on the petroleum operation and contract that often had led them overestimating the forthcoming revenue from oil and gas. Local leaders had greater authority, but many of these leaders levied fees and duties. Foreign companies, particularly in less-developed areas, frequently came under pressure to provide facilities and services provided by the government. Local communities often asked for additional gains by promoting extra-contractual concessions and monopoly arrangements between foreign and local firms. This would create uncertainty and decrease the new investment levels (Hasan, 2001:10).

Another reformation process occurred; in November 2001 the Parliament (DPR, *Dewan Perwakilan Rakyat*) promulgated the Oil and Gas Law No. 22 of 2001, which replaced the 1960 Oil and Gas Law and Law of Pertamina No. 8 of 1971. This law eliminated Pertamina’s monopoly over the upstream and downstream sectors and transferred Pertamina’s responsibility for administering the upstream petroleum sector to the government through a new implementation agency named *Badan Pelaksana Kegiatan Usaha Hulu Minyak dan Gas Bumi* (BP Migas) and downstream petroleum sector to *Badan Pengatur* (BHP Migas).

The Oil and Gas Law No. 22/2001 stated that, petroleum business activities are divided into upstream business activities and downstream business activities. The BP Migas shall conduct supervision on the implementation of upstream business activities on the cooperation contract, while the BHP Migas shall conduct supervision on the implementation of downstream business activities on the business license.

In upstream business activities, the law stated that, the government as the holder of the mining controls the oil and gas resources. The minister shall determine the business entity/permanent establishment, which will be given the authority to conduct the exploration and production activities in the operational areas. The government as the holder of the mining authority establish the BP Migas to reform the management of the upstream business activities. The business entity or permanent establishment shall conduct upstream business activities based on the cooperation contract with BP Migas, and BP Migas shall appoint the seller of the state's portion of oil and/or gas that will give the maximum benefit for the country.

BP Migas took over Pertamina's upstream functions and management of petroleum contractors, formally established through the Government Regulation No.42 of 2002 on 16th of July 2002. The duties of BP Migas are: to provide advice to the Minister in preparing policy and offering working areas for cooperation; to sign the cooperation contract; to review and submit to the Minister for its approval the first plan of development in a contract area; to approve the subsequent plan of development, excluding the item above; to approve the work program and budget; to monitor and report to the Minister the execution of cooperation contract; and to appoint the seller of the government's share of and/or gas, that can generate the maximum profit for the government.

The effectiveness of the reforms will depend largely on the details of the implementation, where all substantive and procedural changes will need to be issued in the implementing regulations. The transition period in implementing those new laws made uncertainty and some problems.

As example the VAT issue as mentioned in section 2.2.1.3 was becoming more complex as Pertamina function in coordinating PSC contractors was transferred to BP Migas, while the implementation regulation has not been issued. Since May 2003 Pertamina had not been in position to refund the VAT to the PSC. As a result the contractors did not possess receipt of VAT paid, therefore it could not file claim for the refund of VAT that had been paid. According to the information given by Indonesian Petroleum Association (2004) in the pre-conference dialogue no 2 on 13 October 2004, by 1 September 2004 VAT refund to be paid by the Directorate General Tax to the PSC had amounted to around 1 trillions IDR.

By the end of 2003 the GOI had not yet completed its implementing regulations for the upstream and downstream sector. A few key areas considered seriously by the contractor to be included in the regulations were sanctity of contract for existing PSC, the lack of clarity of the DMO and potential overlapping responsibilities between upstream and downstream authorities BP Migas and BHP Migas including natural gas transportation via pipeline (US Embassy: 2004:1-2).

Security remained a major concern for investors, particularly following the terrorist bombing attack in Bali in October 2002, in Hotel J.W. Marriot Jakarta in 2004, in front of Australia's Embassy in Jakarta on 9 September 2004 and other part of Indonesia, renewed military operations in Aceh, as well as separatism and communal violence continuing to challenge national unity in Papua and others. These conditions reduced the attractiveness of petroleum business in Indonesia.

In addition to issues above, the recent trend of mergers, consolidation and acquisitions within the oil and gas industry will place the exploration budget in fewer hand, thereby the number of players seeking for exploration rights is likely to lessen. With acquisitions, petroleum's company could get a good new work area not only with a lower capital investment, but also with a lower risk and shorter lead-time (Hasan, 2001).

To response issues above GOI had provided the incentive to blocks tendered out in 2003, in this study named as Fifth Incentive Package (IP5). Under the IP5, the production sharing split was increased ranging from 80/20 to 65/35 for oil and from 60/40 to 55/45 for gas according to their geological location conditions. Furthermore, the GOI had also offered credits up to 110% for investment credit, and 10% fixed FTP in the sense that it was only for the GOI benefit. The contractor committed to spend 140.9 million USD for the first three contract years that cover geophysical and geological studies, 2D and 3D seismic surveys and drilling of exploration wells. Contractor would also pay signature bonus directly to the government in amount of 26.6 million USD (Table 2.5). The IP5 was successful in increasing the number of contracts signed, to 16 PSC contracts signed in 2003. But the exploration activities were still low, only 41 exploration wells in 2003.

To summarise, to maintain dynamic petroleum E&P activities, the GOI have demonstrated pragmatism in solving the problems occurred. PSC3 with all its incentive packages (IP1, IP2, IP3, IP4 and IP5) was successful to attract investors, in total 134 PSC3 contracts were signed representing 52% of total PSC contracts signed during 1966 – 2003 period. In contrast, the productivity of the PSC3 contract was very low, only 4% were producing. The problems occurred due to the petroleum companies considered the commercial attractiveness of the existing Indonesian PSC needed to be improved, and more incentives for conventional areas, marginal field development and exploration investment in frontier areas were needed. In addition, the investment climate of the Indonesian petroleum E&P business also needed to be improved.

Although there were declining tendencies in productions and (see Figure 2.7, 2.8 and 2.9) decreasing contribution of petroleum to GDP from 12% in 1991 to below 10% in 2002 – 2004, notwithstanding the currently high oil prices; however the petroleum sector will continue to play an important role in the economic development of Indonesia in the future, not only as the major source of revenues but also as the sources for supplying energy for domestic requirement and the feedstock to strategic industry as well as to support of the growth of many areas where mining activities exist due to multipliers effect, creating considerable number of employment across the country and others respectively. This means the GOI must resolve all those problems as soon as possible.

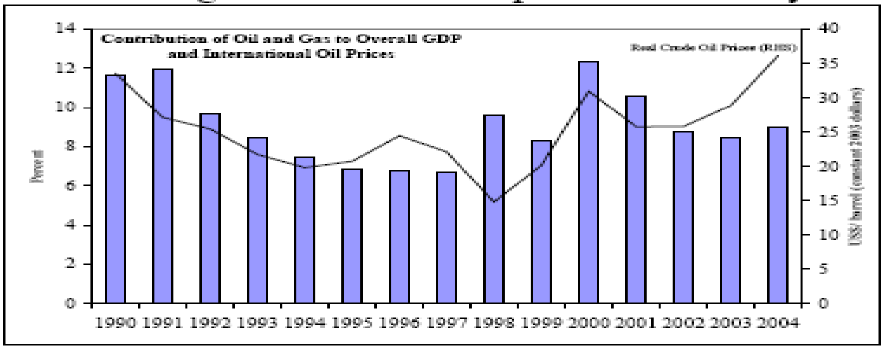


Figure 2.7: Indonesia's income from petroleum business (IMF, 2005:58)

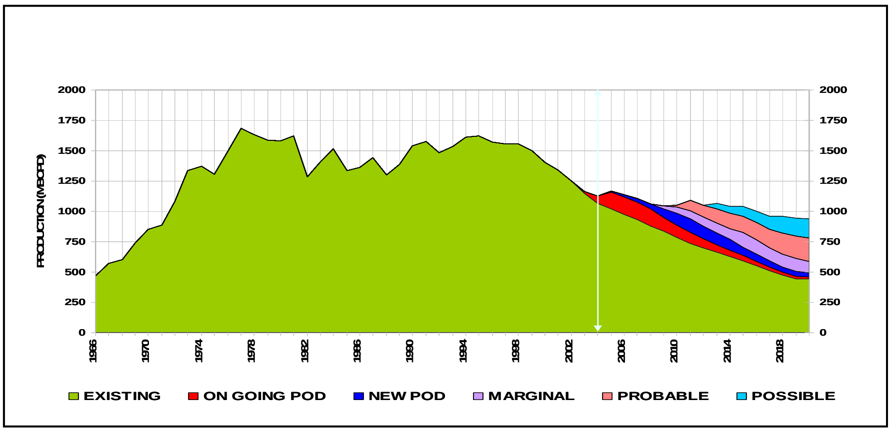


Figure 2.8: Indonesia's historical oil production 1966 – 2004 and projection through 2015 (Warnika, 2005)

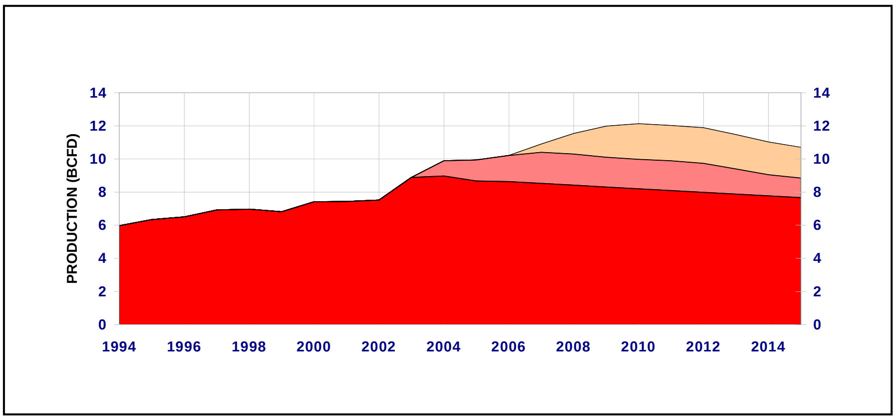


Figure 2.9: Indonesia's gas historical production 1994 – 2004 and projection through 2015 (Warnika, 2005)

2.2.2. The Indonesian Production Sharing Contract Terms and Variables

Some of the definition of the PSC variables can be shown in Table 2.5. The brief discussions of some PSC terms and variables are as follows.

2.2.2.1. Title of the Resources, Management Clause, Right and Obligation of Parties

Title of the resources was vested in the BP Migas (previously in Pertamina) on behalf of the GOI either in its geological or at any phase of production. Legally the PSC granted the contractor the right to receive an allocation of production for risks assumed and services rendered. This payment in the form of production is made at the point of export if there is a commercial discovery.

In Indonesian PSC, BP Migas is responsible for the management of petroleum operations, and the contractor is responsible to BP MIGAS for execution of the agreed work program. Contractor agrees to provide all the financial, technical, skill, equipment necessary, personnel and others required for performance of the work program operations. Contractor carries out such operations at its sole risk and cost, which will be reimbursed out of commercial production. All operations must maintain its environment. After the contract relinquishment of part of area, contractor must remove all installations in a manner acceptable and perform all necessary restoration activities in accordance with applicable GOI regulations to prevent hazards to human life, property of others and environment.

According to Machmud (2000: 119-120) the management clause in the Indonesian PSC and Malaysian PSC was almost identical in written, but in practice they handled their task differently. The Malaysian PSC exercise management through Joint Management Committee (JMC), consisting of representatives of Petronas and contractor with unanimous decision. The JMC met occasionally as required and exercises a loose management style, management by exception and operating by guidelines more than by directive. China also had a JMC, consisted of representatives of state owned company and contractor and the decision was made amicably through consultation and unanimous. The Chinese JMC presents their management on a day-to-day basis; prefer a more hands-on style.

In contrast Indonesian PSC exercises management through a designated bureaucracy, the former BPPKA as a sub division of Pertamina (now BP Migas), involved in every aspects of operations and likes to operate by directive. Moreover there are other agencies in Indonesia (e.g. MIGAS, BPKP, the state auditing agency, a subdivision of Ministry of Finance) that in certain instances directly deal with the contractor. Machmud (2000:183) also found some problems occurred in the execution of management clause of the Indonesian PSC such as bureaucracy, tendering rule, the role of BPPKA/Pertamina, the RPTK process on personnel management, crypto taxes, the mark up myth, and others. As opposed to China and Malaysia, Indonesia has *x* factor that made it difficult for investor to calculate cost and profitability. He said that if this *x* factor left unchecked, latter situation would prove extremely damaging to the attractiveness of Indonesian petroleum business.

2.2.2.2. Duration, Contract Area and Relinquishment/Exclusion of Area

The duration of Indonesian PSC system is 30 years, divided into two phases. The first is the exploration phase, which lasts for a six to ten years from the effective date of contract. If at the end of the initial six years as from the effective date or the four years extension no petroleum in commercial quantities is discovered, then the contract shall automatically be terminated entirely. The second phase is the production phase, which commences from the date the area is declared commercial and continues to the conclusion of the contract term. At the end of 30 years operations, the contract will be terminated, or can be extended. Both parties must approve the extension of contract. In comparison with Malaysia and China, the Chinese PSC had similar duration contract as Indonesian PSC, 30 years; while the duration contract on Malaysian PSC was 24 years in conventional field contract and 38 years in deepwater field contract (Machmud, 2000).

In the Indonesian PSC, the contract area differed from one contract to another, ranging significantly from some 240 km^2 to 320,000 km^2. It tended to be smaller in recent years.

Relinquishment is a standing requirement in PSC, which provides two type of surrender: mandatory and optional relinquishment. The general purpose of exclusions and relinquishments requirement in the contract is to put sufficient pressure on the contractor to assure a continuous work effort in the contract area. If the contractor's efforts fail, the exclusion mechanism allows for the relinquished areas to be put up for bid again, so another party can attempt to make it work.

In Indonesian PSC, under the mandatory relinquishment provision, on or before the end of the initial three years period as from the effective date, contractor shall relinquish 25% of the original total contract area and at the end of the sixth period shall relinquish 25% of the original total contract area. Before the end of tenth contract year, after relinquishment contract area shall not be in excess of 20% of the original total contract area. At the end of contract year, if GOI and contractor do not agree to extend the contract, contractor shall have the right to relinquish any portion of contract area. While under optional surrender provision, the contractor is given the right to surrender at the end of the second contract year and prior to the end of any subsequent year any portion of the contract area upon giving 30 days notice to BP Migas. The entire contract area must be returned if no discovery is made by the end of the exploration period, unless an extension is granted.

2.2.2.3. Minimum Exploration Expenditures Commitment and Bonuses

Minimum exploration expenditures commitment is a major obligation in the PSC contract. The contractor is required to commence petroleum operations not later than six months after the effective date of contract and to spend in each of the initial 6 – 10 year exploration periods the minimum rates of exploration expenditure as specified in the contract. Any under expenditures in the given year may be carried forward to the next year, and over expenditures can be automatically subtracted from the subsequent year's commitment. In the IP5, contractor was committed to spend 140.9 millions USD for the first three contract years that covered geophysical and geological studies, 2D and 3D seismic surveys and drilling of exploration wells.

Compared to Malaysian PSC and Chinese PSC, the minimum exploration expenditures commitment in Indonesian PSC appears to be the most lenient, it simply allows carry-overs in case of a deficit in annual minimum expenditures; and in case of the expenditures over the minimum commitment, it allows credits against the next year's commitment. Malaysia requires a performance guarantee and allows carry over only if justifiable. While in China PSC, it allows carry over of deficit from one exploration phase to another only after approval from CNOOC and unfulfilled commitments in the last exploration phase must be established in cash (Machmud (2000:123).

Bonus payments are borne solely by the contractor and cannot be included in the operating costs, which are recoverable from production, but can be charged against tax liabilities once profitable operation commences. There are two types of bonuses in Indonesian PSC, first is signature bonus and second production bonus. Signature bonus is to be paid after approval of the contract for information concerning the acreage field held by government and made available to the contractor. The amounts are varies from contract to contract from 1 million to 5 million USD; under the IP5 the amount of signature bonus is 26.6 million USD.

Production bonus is a compulsory payment by contractor and to be paid once production reaches certain specified level over a period time, usually 120 consecutive days. The number and amount of the bonus vary from contract to contract, depending perhaps on the geology potential of the area. Usually in Indonesian PSC the triggering production starts from a low of 0 – 50 MBOPD to a high of 100 – 500 MBOPD, with the total commitment ranging commonly from 15 million to 50 million USD. The higher the signature and production bonuses can make the contractor's NPV and IRR lower.

The result of Bindemann's study (1999:52) found that during 1966 to 1998 Eastern Europe and Asia had the lowest signature bonuses, while the highest were in the Middle East and Central America. While Machmud (2000:126-126) found that Malaysian PSC did not have bonus payment requirement, but China PSC had it. Both bonus payments in Indonesian PSC and Chinese PSC were not cost recoverable.

Table 2.5. : Definition of some PSC variables

Variables	Definition
First Tranche Petroleum (FTP)	A portion of petroleum production taken firstly before any deduction of cost recovery and will be shared between GOI and contractor per year based on production sharing split as specified in the contract.
Investment Credit (IC)	Investment Credit allows the contractor to recover an additional percentage of capital costs through cost recovery. The credit is taken out of gross production before recovering the expenditures.
Cost Recovey	The recovering of the exploration, development and production expenditures to the contractor from any petroleum produced.
Profit oil or profit gas	The remaining revenues after royalty (if applicable), FTP, investment credit (if applicable) and cost recovery.
Production Sharing Split	The rate of production sharing split between the GOI and the contractor.
Domestic Market Obligation (DMO)	A percentage of the contractor's profit oil should be sold to the government at discounted price. The quantity of the DMO varies from contract to contract, provided that the pro rata quantity does not exceed 25% of total production from its contract area
DMO price (DMOpr)	The price of the DMO that are paid by GOI to the contractor after DMO holiday price ended.
DMO holiday price (DMOhol)	The time that contractor get the price of oil for DMO as export price. Under Indonesian PSC the DMO holiday price set up at 5 first years (or 60 month) since the first production commences.
Taxation	The contractor tax liabilities refer to the relevant tax law

2.2.2.4. First Tranche Petroleum

FTP, which was first introduced by Indonesia in IP1 in 1988, is a portion of petroleum production amounting some percentage of production taken up firstly before deduction of cost recovery and will be shared between GOI and the contractor every year on the basis of applicable profit sharing split. The objective of the FTP payment is to ensure the GOI revenues at the first production and to ensure that marginal field still generate revenues for the GOI. Contractor share from FTP is also taxable. FTP effectively is like royalty payment or cost recovery limit, with the rate is the royalty rate multiplies production sharing split, so investor valued FTP as one of an inefficient PSC term. Especially for marginal fields with low net cash flow even before FTP, it might reduce that cash flow to zero and make the field uneconomic. Initially, under IP1, the FTP size was 20% of production and shared between GOI and contractor. It was then decreased to 15% under IP4, still shared between GOI and contractor; and then under IP5 was decreased again to10% but, all for the GOI benefit. In effect, this FTP for GOI benefit only is similar to royalty payment. The higher the royalty payment the lower NPV is.

Bindemann (1999: 48-49) found that during 1966 to 1998, royalties in Asia and Eastern Europe have on average been much lower than other regions; the averages were below 4% and 5% respectively whereas the rest of the world has an average between 7% and 9%. The rates of royalty diverged. In Asia royalties vary between zeros to 12.5%, while in Eastern Europe it vary between zeros to 17.5%. In fact PSC contracts in the Bindemann study dataset fell into four categories of zero, 10%, 12.5%, and 20% royalties. One country had more than 20% royalty (Chile with 45%) and only five countries had less than 10% royalty. Analysis also showed that net exporter countries charged higher royalties than net importers, and onshore contracts were relatively tougher for the petroleum company than offshore contracts. The 10% FTP of the IP5 (100% goes to GOI) could be considered as royalty payment, which was above average of royalties in Asia countries. However, the rate was relatively low, hence it was still attractive. But if the entire FTP goes to GOI then the basic concept of FTP has changed.

2.2.2.5. Investment Credit

Indonesia introduced the concept of investment credit in 1977 under PSC2 system. Investment Credit (IC) allows the contractor to recover an additional percentage of capital expenditures for production facilities through cost recovery. The credit is taken out of gross production before recovering the expenditures. The IC is subject to taxation and may be carried forward to succeeding years if it is not fully taken. Currently under the IP5, it amounted up to 110% depending on the geological condition. Higher investment credit size results in higher income to contractor.

2.2.2.6. Cost Recovery

The contractor is allowed to recover all the expenditures of petroleum operations from their production after deduction of FTP through cost recovery mechanism. Cost recovery is made up of: exploration, development and production expenditures; current depreciation and amortisation; interest on financing (if allowed as specified in contract); investment-credit (if allowed as specified in contract), and the un-recovered costs carried forward from previous years. The portion of petroleum used for reimbursement of the expenditures is commonly referred to as *cost oil*. BP Migas on behalf of the GOI must approve all expenditures for recovery. Cost recovery is calculated annually and all goes to contractor. Generally gas cost recovery is calculated separately from oil cost recovery.

In Indonesian PSC system, all expenditures associated with a given block/contract must be recovered from revenues generated within that block/contract, it is called that the block/contract is ring fenced. This stipulation has a huge impact on the recovery of expenditures of exploration and development.

Expenditures above are classified as capital and non-capital expenditures. Capital expenditures, which mean expenditures made for items that normally have a useful life beyond the year incurred, includes equipment, tangible properties, building, transportation facilities and others. While non capital expenditures, which refer to those expenditures incurred and related to current year's operations, includes wages, salaries, administration, exploration expenditures, drilling expenditures, production expenditures, rental payment and others.

Capital expenditures are recovered in the form of depreciation method, which carry over one half of the depreciation life by the double-declining balance method. Recovering capital expenditures through depreciation is valued as one of the inefficient terms of PSC, since it will delay in recovering the costs; in particular it might make marginal field uneconomic.

The non-capital expenditures can be recovered directly in the current year as soon as income is available from the contract area and the un-recovered expenditures are reimbursed on a straight-line basis. In the current Indonesian PSC system, the expenditures can be recovered annually without limit; and the unrecovered costs can be carried forward in the case the production is not enough to recover them.

During 1966 to 1998, almost half of all contracts in the dataset of Bindemann study (1999:49-50) specified cost recovery limit at either 40% or 100%, while almost one-third were at 30% or 50%. Only 2.5% of the dataset were at zero and the remaining 20.5% of the dataset was concentrated in the 20% to 29% bracket and the 51 to 99% bracket. These facts suggest the Indonesian PSC has an attractive cost recovery term.

2.2.2.7. Production Sharing Split

Production sharing split is the main term in PSC. Profit oil or profit gas is gross revenue less the FTP less cost recovery less investment credit. This profit is shared between the contractor and the GOI by using the production sharing split as specified in the contract. The contractor's share of profit is also subjected to taxation.

The progressiveness of the development of the production sharing split in the Indonesian PSC could be seen in Table 2.1 and Table 2.4. Currently, under the IP5 terms, GOI increased the production sharing split again, after-tax production sharing split ranging from 80/20 to 65/35 for oil and from 60/40 to 55/45 for gas in favour of GOI depending on their geological condition.

Several studies done by Arco (Machmud, 2000: 128 – 129), Johnston (1994: 130-131), Yuwono (1998) and Dharmadji and Parlindungan (2002) found that compared to Malaysian and Chinese PSCs, the Indonesian PSC for conventional areas (before the IP5, with production sharing split 85/15) was nearly equal to Malaysian PSC and valued as the toughest fiscal term in the world; however, the Indonesian PSC for frontier and deepwater areas was the best among the three (Machmud, 2000: 130 – 134).

According Johnston (1994, 64), as illustrated in Figure 2.10, there is the effective trade-off of geological potential, success rate, field size, maturity factor, infrastructure and other key factors that influence business decisions against contractor take. Increase in the geological potential, success rate, field size, maturity factor, infrastructure and others might decrease the contractor production sharing split; ranging between the lowest of 15% and the highest of 55%. The progressiveness of the increasing of contractor production sharing split in Indonesian PSC showed that GOI and Johnston have similar view, the ranging of contractor production sharing split under IP5 (between 20% - 35% depends on the geological condition) was in the range stated above and the more difficult geological potential the higher production sharing split is.

Only 45 of the 268 PSC contracts in Bindemann (1999:50) data set had fixed profit oil sharing split, the remaining have some kind of sliding scale that either based on output or rate of return. Table 2.6 shows that during 1966 to 1998 period, the highest maximum average profit oil-sharing split for the contractor was found in Central America, at 65%, while the lowest was in Middle East, at 28%. While Central America, Eastern Europe and South America with up to 39% granted the most generous minimum-sharing split to the contractor. The spread between the highest and lowest maximum varies from 10-percentage point in South America to

85 point in Asia and South Central Africa. Recently maximum-sharing split of profit oil tends to increase in all regions except in Middle East, where from an average of 27%, it declines significantly lower than elsewhere. Exporter countries offer less favourable sharing split to the contractor than importer countries (Bindemann, 1999:51). The IP5 has production sharing split based on geological condition; the minimum formula was below the average minimum of Asia countries, but the maximum split was slightly higher than the average maximum of Asia countries. These facts indicate that the minimum formula of the IP5 might need to be improved.

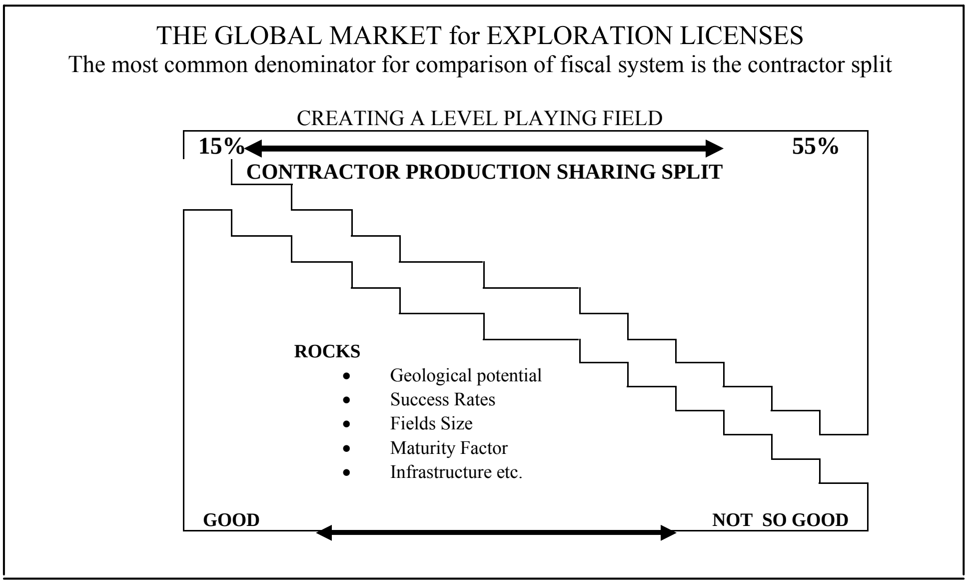


Figure 2.10: Creating a level playing field (Johnston, D., 1994:64)

Table 2.6: Production/profit oil sharing split for contractor of 268 PSC contracts during 1966 –1998 period (Bindemann, 1999:51)

Country	Average Prod. Sharing Split		Max. Prod. Sharing Split		Min. Prod. Sharing Split	
	Max	Min	Highest	Lowest	Highest	Lowest
Asia	44.15	28.21	100	15	60	10
Central America	64.71	36.57	95	40	85	20
South America	48.00	38.80	50	40	50	30
Eastern Europe	51.93	37.00	80	40	60	10
Middle East	27.80	15.75	60	11.8	40	7.5
North Africa	38.67	18.00	100	19	50	10
South Central Africa	55.69	29.17	100	15	75	5

2.2.2.8. Domestic Market Obligation

Indonesian PSC have incorporated a uniform provision, obliging contractor to fulfil their obligations toward the supply of the domestic market in Indonesia with the price below the market, called Domestic Market Obligation (DMO). The goal of DMO is to give security for the oil and gas domestic supplies for the Indonesia. The quantity of the DMO varies from contract to contract, provided that the pro rata quantity does not exceed 25% of total production from its contract area. The oil price for DMO prior to 1984 was 0.20 USD per barrel; after that this price had increased several times, and currently under IP5 it was 25% of the export price for marginal field both new and old oil, while for conventional field it was 15% of the export price. The contractor consider that DMO requirement can reduce the NPV and IRR of contractor, if in any year, recoverable expenditures exceed the difference of gross revenues less FTP and investment credit especially due to the low DMO Price (Dharmadji and Parlindungan, 2002:7).

China PSC does not have DMO obligation, while in the Malaysian PSC DMO was imposed only in the event of national emergency or shortage of supply of oil to the domestic market with normal oil price (Machmud, 2000: 124).

2.2.2.9. Taxation

Merriam-Webster's Dictionary of Law (1996) defines taxation is a charge against a citizen's person or property or activity for the support of government based by the Law. This system used by governments to obtain money from people and organizations. The objective of taxation is the only practical means of raising the revenue to finance government spending on the goods and public services (Tanzi and Zee, 2001:1; and Toni, 2005:2).

The taxation provisions of the PSC usually override the general tax law, especially with regards to corporate income tax. The rates of corporate income taxes for PSC contractor are as follows:

- PSC signed before 1985 were subject to 45% corporate tax and dividend withholding tax at 20% on balance, totalling to 56% tax rate.
- PSC signed between 1985 and 1994 were subject to 35% corporate tax and dividend withholding tax at 20% on balance, totalling to 48% tax rate.
- PSC signed between 1995 to present are subject to 30% corporate tax and dividend withholding tax at 20% on balance, totalling to 44% tax rate.

The changes on the tax rate have no effect on the contractor after tax share. The before tax production sharing split are calculated with fixed after tax production sharing split.

Though the principle of the Income Tax Law dated 9 November 1994 allows tax consolidation in certain business sectors, but it is not allowed in petroleum business. In Indonesian PSC system, the tax income associated with a given block/contract must be recovered or paid from revenues generated within that block/contract; the block/contract is ring fenced. In practice this means that a company working on one contract while developing another new one contract cannot reduce its taxable income from the former contract. The objective of ring fence is to protect present tax revenues. The most common ring fence is applied within the block/contract of the petroleum deposit. Too tight ring-fence can discourage exploration and investment activities. Loosening the ring fencing can be done through widening the boundary incorporating several blocks/contract of the similar company (Baunsgaard, 2001:7). It means applies tax consolidation among several blocks/contract. Tax consolidation means that expenditures in non-producing contract(s) can be deducted from the income in producing contracts of the same contractor(s) for determination of taxable income. It implies with risk sharing between the host government and the contractor, because some of exploration costs are borne by the host government. Tax consolidation application resulting in reducing the contractor’s expenditures, therefore tax consolidation is one of possible incentive can be offered.

2.2.2.10. Participation, Employment, Training, Local preference and Submission of Information

Participation requirement becomes a standing clause for all Indonesian PSC since the PSC2 (1976). The participation clause provides that GOI (was delegated to BP Migas) has the right to demand a 10% undivided interest to be offered to either a limited liability company or Indonesian entity, collectively called Indonesia Participation. The demand is to be made upon commercial discovery, therefore assumes no exploration risks.

Under Malaysian PSC, the Petronas Carigali on behalf of Malaysia government has the right to get minimum 15% of equity (Machmud, 2000: 125). The interest is carried throughout the exploration phase. While under China PSC, the China National Company, CNOOC, has the right to participate as full partner to maximum 51% at the time development phase commences. In modern petroleum contract, the participation clause bother most petroleum companies, it can be strong disincentives to the investor (Machmud, 2000: 114).

All Indonesian PSC attach importance to the issue of Indonesiation, which is realised through training, education and employment of Indonesian personnel for all job classification. The contractor must seek approval from BP Migas to hire and place employees, and in the event of expatriate hiring, prior approval from the Minister of Mines and Energy is required. The Indonesian personnel employed by the contractor are deemed to have Pertamina status.

As the consequences of the state ownership of natural resources and management control over operations, all Indonesian PSC stipulate that BP Migas have title to all original data resulting from the petroleum operations. Accordingly, contractors are to submit to BP Migas copies of all such original geological, geophysical, drilling well, production and other data and reports. In turn BP Migas makes a promise not to disclose the submitted data to any third party without prior consultation with the contractor.

2.2.3. Financial Diagram Flow and Model of the Indonesian Production Sharing Contract

The financial diagram flow of the Indonesian PSC system can be seen in Figure 2.11, while the financial equation model is shown in Figure 2.12. As the objectives of the Indonesian PSC system are optimising the economic rent for the GOI and reasonable profit for contractor, the financial model of PSC follows diagram as mentioned in sub section 2.1.3.3.

Before petroleum produced, there are only cash out paid by the contractor, consisting of the exploration and development expenditures, and after the commencement of petroleum production then there are additional production expenditures. In case that there is commercial production and assuming that annual petroleum production is P, annual average petroleum price is Prc and gross revenues is GRev, then

$$GRev = P \times Prc$$

Before any other deduction, firstly GRev is subtracted by FTP requirement, with the rate of FTP (ftprate) as specified in the contract,

$$FTP = ftprate \times P \times Prc$$

The FTP is shared between GOI and contractor as production sharing split (cpss) that specified in the PSC contract. The contractor share from FTP (CSFTP) and the GOI share from FTP can be written,

$$\begin{aligned} CSFTP &= cpss \times FTP \\ &= cpss \times (ftprate \times P \times Prc) \end{aligned}$$

While GOI share from FTP are,

$$\begin{aligned} GOISFTP &= FTP - CSFTP \\ &= (ftprate \times P \times Prc) - \{cpss \times (ftprate \times P \times Prc)\} \\ &= (1 - cpss) \times (ftprate \times P \times Prc) \end{aligned}$$

After the subtraction of FTP they become net revenues, NR,

$$NR = GRev - FTP$$

= (P x Prc) – (ftprate x P x Prc)

= (1 – ftprate) x P x Prc

From equations above, it can be seen that the higher FTP rate can lower the contractor share from FTP and net revenues (NR) of the project, while on the other hand increase the GOI share from FTP. Since cost recovery is recovered from NR, the remaining money for recovering the contractor expenditures decreases when FTP rate increases.

If investment credit (IC) is allowed for capital expenditures of production facilities (Capex) at the rate (icrate) as specified in the contract, then

IC = icrate x Capex

Increase in investment credit rate can make higher contractor income, since the investment credit is for the contractor.

The contractor can recover all their exploration, development and production expenditures that consist of non-capital (Nopex), capital expenditures (Capex), investment credit and un-recovered costs carried forward (UEC) through cost recovery mechanism. The capital expenditures will be recovered through depreciation method as specified in the contract. Interest on financing (IR) also can be recovered from cost recovery, if specified in the contract too. The equation of the cost recovery is,

CR = Nopex + Capex* + IC + IR +UEC

= Nopex + Capex* + IR + UEC + (icrate x Capex)

The higher the expenditures of the contractor and investment credit rate are the higher will the cost recovery and contractor income be, since all cost recovery is for the contractor. In optimising the economic rent, the expenditures of the contractor must be made effectively. The expenditures must be classified properly, which ones are the true expenditures and which are not. The classification process must be done transparently in simple procedure. As an example, one method the Malaysian PSC already practices, is by making a list called *negative list,* the list of unrecoverable costs, so those costs that are not in the negative list are recoverable. In the event there are dispute, the disputed costs are resolved through consultations. (Machmud, 2000:98).

After recovering the cost recovery from NR, the remaining revenues is called profit oil (PO) and it is shared between contractor and GOI according to cpss specified in the contract. The contractor profit oil share (CPOS) and GOI profit oil share (GOIPOS),

PO = NR – CR

CPOS = cpss x PO

GOIPOS = PO – CPOS

The higher the cpss is the higher will the contractor profit oil share be, on the other hand, the lower will GOI share from profit oil be. The GOI must offer the cpss carefully in optimising the economic rent while still providing sufficient contractor's profitability.

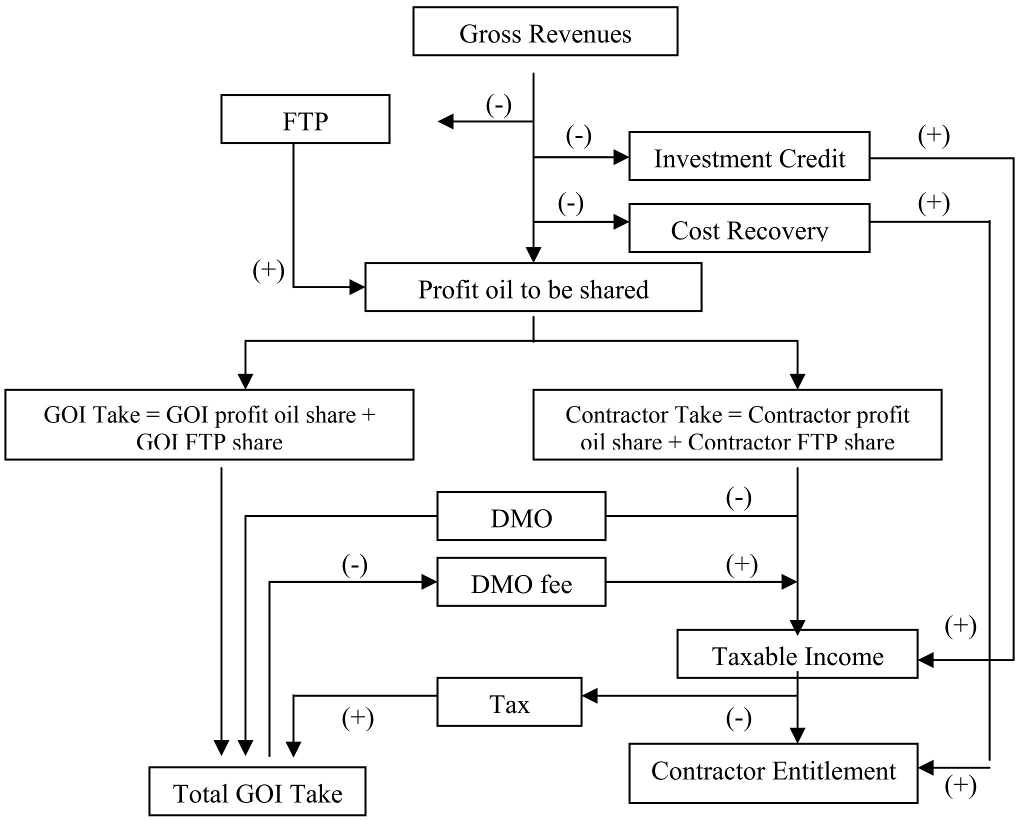


Figure 2.11: Diagram Flow of the Indonesian Production Sharing Contract

The total contractor share (TCsh) consists of contractor share from FTP plus contractor share from profit oil, TCsh = CFTPS + CPOS

While the GOI Take (GOITk) consists of GOI share from FTP plus GOI share from profit oil,

GOITk = GOIFTPS + GOIPOS

GRev	=	P x Prc
FTP	=	ftprate x P x Prc
CSFTP	=	cpss x FTP
	=	cpss x (ftprate x P x Prc) CSFTP = cpss x FTP
	=	cpss x (ftprate x P x Prc)
GOISFTP	=	FTP – CSFTP
	=	(ftprate x P x Prc) – {cpss x (ftprate x P x Prc)}
	=	(1 – cpss) x (ftprate x P x Prc)
NR	=	GRev – FTP
	=	(P x Prc) – (ftprate x P x Prc)
	=	(1 – ftprate) x P x Prc
IC	=	icrate x Capex
CosRec	=	Nopex + Capex* + IC + IR +UEC
	=	Nopex + Capex* + IR + UEC + (icrate x Capex)
PO	=	NR – CosRec
CPOS	=	cpss x PO
GOIPOS	=	PO - CPOS
TCsh	=	CFTPS + CPOS
GOITk	=	GOIFTPS + GOIPOS
DMO	=	dmorate x CPOS
DMOfee	=	dmoprice x DMO
CTI	=	TCsh – DMO + IC
Tax	=	taxrate x (TCsh – DMO + IC)
CET	=	TCsh – DMO + DMOfee*– Tax + CO
TGOITk	=	GOITk + DMO – DMOfee + Tax

Note: * Recovered through depreciation method as specified in contract

P	=	Annual Production	PO	=	Profit Oil
Prc	=	Average Price annually	CPOS	=	Contractor profit oil share
GRev	=	Gross Revenues	GOIPOS	=	GOI profit oil share
FTP	=	First Tranche Petroleum	cpss	=	Contractor production sharing split
CSFTP	=	Contractor FTP share	TCsh	=	Total Contractor Share
GOISFTP	=	GOI FTP share	GOITk	=	GOI Take
ftprate		First Tranche Petroleum rate	DMO	=	Domestic Market Obligation
IC	=	Investment Credit	dmorate	=	DMO rate
icrate	=	Investment Credit rate	dmoprice	=	DMO price
Cosrec	=	Cost Recovey	CTI	=	Contractor Taxable Income
NR	=	Net Revenues	Tax	=	Tax must be paid by contractor
Nopex	=	Non Capital expenditures	CET	=	Contractor Entitlement
Capex*	=	Capital Expenditures	TGOITk	=	Total GOI Take

Figure 2.12: Financial equation model of the Indonesian PSC

In Indonesian PSC, contractor has obligation to sell a part (dmorate) of its contractor profit oil share in domestic market (DMO) at export price during the first five years of production; after that, at a price (dmoprice) specified in the contract, which is usually below the export price. Therefore during those first five years, the DMO obligation does not influence the income of contractor, while after the first five years, the income of contractor decreases.

DMO = dmorate x CPOS

DMO fee = DMO x dmoprice

Higher dmorate and lower the dmoprice will result in lower contractor take. As DMO is very important in ensuring the oil domestic market in Indonesia, the DMO requirement is still needed. The lower dmoprice needs to be improved. In the Malaysian PSC, the DMO obligation occurs only in the event of state emergency or shortage supply of oil for any reasons, by declaration of government of state. In this case Petronas has the right to pre-empt all or part of oil produced from the contract area at a normal oil price value.

Since cost recovery is tax-free, the contractor’s taxable income (CTI) is the contractor share from FTP plus contractor share from profit oil (TCsh) minus DMO and plus investment credit.

CTI = TCsh – DMO + IC

Tax = taxrate x CTI

The contractor entitlement (CET) consists of the total contractor share minus DMO, plus DMOfee, minus tax and plus the cost recovery. While the Total GOI Take consists of GOI share from FTP plus GOI share from profit oil plus DMO minus DMO price and plus taxes. Hence the CET and Total GOI Take are,

CET = TCsh – DMO + DMOfee - Tax + Cosrec

TGOITk = GOITk + DMO – DMOfee + Tax

Finally, the GOI Take in percentage was the ratio of total GOI takes to Gross Revenues, and the Contractor Take in percentage was the ratio of total contractor entitlement to Gross Revenues.

Yuwono (1998) and Dharmadji and Parlindungan (2002) compared the commercial performances of the Indonesian PSC contract with some other countries through cash flow analysis. In their cash flow analyses, Yuwono used three Indonesia's historical data field, while Dharmadji and Parlindungan used one data field model.

Yuwono (1998) compared the commercial profitability of the Indonesian PSC (with and without incentive packages) with other countries including China, Malaysia, Thailand, USA and Brazil. The financial analyses used Indonesia's historical financial and production data of three contracts that were operated in Indonesia that had average production of 87, 39 and 22 MBOD. The profitability variables they used involving Net Present Value at LIBOR rate as discount rate (NPV@6%), internal rate of return (IRR), pay-out time (POT), government take and contractor take.

Table 2.7 shows the summary of the fiscal regimes of those countries and the result of their cash flow analysis. Various contract types were used in those countries. Indonesia and Malaysia used PSC, China used PSC hybrid, while Thailand and USA used RAT, and Brazil used RSC system.

China, USA and Thailand had sliding scale royalty payment; in China it was based on production profile, and so was in Thailand but with maximum 15% royalty rate, while in USA it was based on location condition with rate varied from 12.5% to 20%. Malaysia had fixed 10% royalty, while Indonesia did not have royalty payment, but it had FTP requirement that was shared between parties; contractors argued that the FTP was effectively royalty payment. On the other hand, Brazil did not have royalty payment. China and Malaysia had limit on cost recovery payment. In China, it was limited to 50% of gross revenues, while in Malaysia it was limited to 20% of gross production.

Tax rate was set at 48% in Indonesia; at 33% in China; at 45% plus 25% duty on profit exported in Malaysia; at 50% in Thailand; at 6% production tax plus income tax 46% plus windfall tax $\geq$ 81% in USA; while it was set at 25% in Brazil.

Table 2.7: Summary of fiscal regimes and the result of Indonesia, China, Malaysia, Thailand, USA and Brazil comparative analysis (Yuwono, 1998:57-59)

Items	Indonesia	China	Malaysia	Thailand	USA	Brazil
Type	PSC	PSC hybrid	PSC	RAT	RAT	RSC
Duration Exploration Dev+ Production	30 years 3 years 30 years	 7 years 12+15 ys	 5 years 20 years	39 years 2,3,4 years 20 +10 years	 5-10 ys until not prod.	
Bonuses Signature bonus Production bonus	 Yes Yes	 Yes No	None	Yes		
Royalty	Effective royalty with FTP	Sliding based production	10%	Sliding rate prod.max 15%	12.5% – 20% depends on loc	
Cost Recovery		Limited to 50% of gross rev.	Limited to 20% of gros prod.			
Profit share before tax (in favour of gov)	71.15/28.85	Varies based on annual gross prod. (X factor)	70/30 (PSC 1985)			
Taxes	48%	33%	45% 25% duty on profit exported	50%	Prod. Tax 6% Inco tax 46% Windfall tax other -> 81%	25%
Other	DMO With incentives		70% supple. Payment if price over base	DMO Surface rental SRB windfall profit based increment oil price		Commerciali prod.110% of all costs Sliding scale remuneration Buy-back
Gov. Particip.	10%	51%	15%	Max 20%		
Model 1 1969 – 1996 (average production 87 MBOD)						
Incentive Package NPV@6%, billion USD IRR, % POT, year Government Take, % Contractor Take, %	applied 3,198 35% 6 62% 38%	2,764 30% 8 63% 37%	3,252 30% 8 61% 39%	3200 36% 7 62% 38%	2,347 31% 7 63% 37%	4,082 34% 8 59% 41%
Incentive Package NPV@6%, billion USD IRR, % POT, year Government Take, % Contractor Take, %	no 2.709 27% 8 63% 37%					
Model 2 1979 – 1996 (average production 39 MBOD)						
Incentive Package NPV@6%, billion USD IRR, % POT, year Government Take, % Contractor Take, %	applied 1,340 31 7 39 61	109 9 8 & 20 57 43	(151) 3 9&20 59 41	544 24 7 53 47	218 10 11 & 19 53 47	193 10% 9&19 54 46
Model 3 1984 – 1996 (average production 22 MBOD)						
Incentive Package NPV@6%, billion USD IRR, % POT, year Government Take, % Contractor Take, %	applied 635 21 10 42 58	63 8% 14 53 47	(221) -2 >20 59 41	441 14 13 44 56	182 10 15 49 51	240 12 13 49 51

In addition, Indonesia had DMO requirement, Malaysia had 70% supplement payment if price was higher than the base price, Thailand had DMO surface rental

(SRB) windfall profit based on increment oil price, and Brazil had commerciality production 110% of all costs sliding scale remuneration buy-back. The highest government participation was in China at 51%, at maximum 20% in Thailand, at 15% in Malaysia and at 10% in Indonesia. Profit oil share before tax in Indonesia was 71.15%/28.85%, in Malaysia it was 70/30 in favour of government, while in China it varied based on annual gross production (X factor).

Yuwono found that the Indonesian PSC with Incentive Package system was very attractive, ranked second to only Thailand. He suggested some of the Indonesian PSC's variables are need to be revised, including the length of DMO holiday price; the criteria's of interest recovery for the exploration needs to be defined clearly. According to him, tax consolidation was not in line with the basic philosophy of the PSC's systems and the win-win solution (Yuwono, 1998:72).

Dharmadji and Parlindungan (2002) made a comparison of fiscal regimes in the Asia Pacific region, including Australia, China, India, Indonesia and Malaysia through cash flow simulation analysis based on generic model of each fiscal regime of those countries with the same field data model. The profitability variables they used included net present value at 10% discount rate (NPV@10%), internal rate of return (IRR), pay out time (POT), profit to investment ratio (P/I) and contractor take.

Table 2.8 shows the summary of fiscal regimes, the model used and the economics' indicator as result of the cash flow analysis of the countries that was done by Dharmadji and Parlindungan. Only Australia used RAT system, the other countries applied PSC system. Based on the size of their proven oil reserves in year 2000, China owned the highest reserves size, followed by Indonesia, Malaysia, India and Australia. In term of production size in 2000, China also ranked as the highest oil producer, followed by Indonesia, Malaysia, Australia and India.

Australia had royalty requirement, varied from 10 to 12.5% based on production and 40% of PRRT; in China royalty varied based on production rate, in India the royalty was 12.5% for onshore and 10% offshore, in Malaysia it was 10%; while in Indonesia, it was effectively the FTP.

Table 2.8: Summary of fiscal regimes and economic indicators of some Asia Pacific countries (Dharmadji and Parlindungan, 2002:2-6)

<table>
<tr><th>Items</th><th>Australia</th><th>China</th><th>India</th><th>Malaysia</th><th>Indonesia</th></tr>
<tr><td>Type</td><td>1. Royalty Excise
2. PRRT</td><td>PSC</td><td>PSC</td><td>PSC</td><td>PSC</td></tr>
<tr><td>Duration
Exploration
Production</td><td>6 years
21 years</td><td>7 years
15 years</td><td>7 years
20 years</td><td>5 years
20 years</td><td>3 years
30 years</td></tr>
<tr><td>Bonuses
Signature bonus
Production bonus</td><td>None</td><td>Yes
No</td><td>None</td><td>None</td><td>Yes
Yes</td></tr>
<tr><td>Royalty</td><td>1. Royalty 10%--12.5% Excise based on production
2. PRRT 40%</td><td>Varies based on production rate</td><td>12.5% onshore
10% offshore</td><td>10%</td><td>Effective royalty with FTP</td></tr>
<tr><td>Cost Recovery</td><td></td><td>Limited to 50% of gross revenues</td><td>No limit</td><td>Max 50% for oil and 60% for gas</td><td></td></tr>
<tr><td>Profit share (in favour of government)</td><td>None</td><td>Varies based on annual gross production</td><td>Varies based on Investment Multiple</td><td>Varies based on production</td><td>71.15/28.85</td></tr>
<tr><td>Taxes</td><td>36%</td><td>33%</td><td>50%</td><td>45%
25% duty on profit exported</td><td>48%</td></tr>
<tr><td>Other</td><td></td><td></td><td></td><td>70% supplementary payment if price over base</td><td>Domestic Market Obligation</td></tr>
<tr><td>2000’s Oil prod. Bopd</td><td>722,799</td><td>3,195,000</td><td>535,742</td><td>780,000</td><td>1,460,693</td></tr>
<tr><td>2000’s proven oil reserves, million barrels</td><td>2,835</td><td>30,600</td><td>3,338</td><td>5,050</td><td>9,665</td></tr>
<tr><th colspan="6">Assumption of the field model</th></tr>
<tr><td>Field size, MMBBL</td><td>150</td><td colspan="3">Initial oil price, USD/BL</td><td>18</td></tr>
<tr><td>Peak production rate, bopd</td><td>80,000</td><td colspan="3">Oil price escalation, %</td><td>3</td></tr>
<tr><td>Decline rate, %</td><td>15</td><td colspan="3">Capital investment, million USD</td><td>150</td></tr>
<tr><td>Field life, year</td><td>11</td><td colspan="3">Operating cost, USD/BL</td><td>5</td></tr>
<tr><td></td><td></td><td colspan="3">Capital and operating costs escalation</td><td>3</td></tr>
<tr><th colspan="6">Result: Economic Indicator</th></tr>
<tr><td>NPV@10%, E3 USD</td><td>468,415</td><td>449,003</td><td>246,815</td><td>159,088</td><td>123,815</td></tr>
<tr><td>IRR, %</td><td>79.4</td><td>65.0</td><td>51.8</td><td>38.3</td><td>31.7</td></tr>
<tr><td>POT, year</td><td>2.5</td><td>2.9</td><td>2.9</td><td>3.1</td><td>3.2</td></tr>
<tr><td>P/I ratio</td><td>6.6</td><td>6.1</td><td>3.3</td><td>2.3</td><td>1.9</td></tr>
<tr><td>Contractor Take, %</td><td>41.7</td><td>42.4</td><td>23.0</td><td>16.4</td><td>13.3</td></tr>
</table>

Two countries had limit on cost recovery; in China the limit was 50% of gross revenues while in Malaysia it was 50% of gross revenues. Only Indonesia had fixed profit sharing, 71.15/28.85 before tax in favour of government. In China it varied based on gross production, in India it varied based on investment multiple while in Malaysia it varied based on production.

The lowest tax rate was 33% in China, followed by 36% in Australia (but it had high PRRT 40%), then by 48% in Indonesia. In India the tax rate was 50% while in Malaysia it was 45% plus 25% duty on profit exported. Other requirements were that Malaysia had 70% supplementary payment if price was higher than the base and Indonesia had DMO obligation.

The result showed that from their economic indicators, Australia was the most favourable, followed by China, India, Malaysia and Indonesia as the second most to the least respectively. Although China had the highest reserves and production size, its economic indicator ranked as the second favourable after Australia.

Each of parameters (bonuses, royalty, cost recover limit, contractor profit split, taxes and DMO) influenced the contractor’s cash flow, NPV and contractor take. The higher bonuses, royalty, taxes and DMO are the lower the contractor’s cash flow, NPV and contractors take. Cost recovery limit and contractor profit oil sharing split had the most significant influence on contractor cash flow, the higher cost recovery limit and the higher the contractor profit oil sharing the better. They suggested that contractor needs a good understanding on fiscal terms to make a good investment decision, while the government needs to understand its country condition and other countries in the region in order to develop a competitive fiscal term. Improvement of the Indonesian PSC terms must be considered seriously.

Both Yuwono’s and Dharmadji and Parlindungan’s analyses suggested that Indonesian PSC without Incentive Package was the least attractive among the compared countries. This fact suggests that the Indonesian PSC without Incentive Package need to be improved.

Yuwono used 6% and Dharmadji used 10% discount rate, meanwhile only one field data model used in Dharmadji and Parlindungan’s analyses and three samples field below 100 MBOD used in Yuwono analyses. The Indonesian PSC1 (for standard conventional field) and the Third Incentive Package terms and variables were used in these analyses. To understand the commercial performances of the

Indonesian PSC as a whole are not adequate with only one field model or only three data field to be analysed, they need more records and variability of samples. While each petroleum company has its discount rate that depends on its financial conditions, from unofficial information we obtained, some companies used discount rate of 10%, 15%, 25% or even higher of 40%. Moreover recent the Indonesian PSC already offered the Fifth Incentives Package that sound more profitable for the investor. That is why more accurate analyses of Indonesian PSCs' commercial performances were needed be done.

2.3. Decision Analysis under Risk and Uncertainty

2.3.1. Identifying the Impact of Tax Consolidation Application in Frontier Areas

2.3.1.1. The Need for Identifying the Impact of Tax Consolidation Application in Frontier Areas

Given declining tendencies on Indonesia's geological potential especially in western part of Indonesia, while the remaining basins (proved reserves, unproved reserves and have not been drilled) have been found largely in eastern part of Indonesia, deep water and frontier areas that have higher risks and costs. Moreover risk capital is being more scarce and competitive. Therefore Indonesia needs more strong incentives for exploration investment in high-risk isolated frontier and deepwater areas.

Successful development of any potential petroleum prospect in frontier and deepwater will require an acceptable mix of favourable reservoir performance, attractive commercial contract terms, sound regulations, and production technologies that can meet the challenge. Reservoir performance and commercial incentives are two important drivers in searching oil and gas resources, while technological advancements are critical for developing them economically (Bergman, 1999). As already mentioned earlier, the commercial risk can be reduced by the government, for example by making freely available exploration data or by financing exploration activities (Baunsgaard, 2001:6). Financing a part of exploration activities can be done through tax consolidation. Tax consolidation means that expenditures in non-producing contract(s) can be deducted from the income in producing contracts of the same contractor(s) for determination of taxable income. The tax consolidation implies some sharing of exploration risk between the contractor and the government. From the government point of view, the application of tax consolidation represents current investment by Indonesia for the future; specifically it represents the reinvestment of a part of current government oil and gas revenue today to raise the level of exploration activity in achieving profit in the future. That is why the tax consolidation is one of possible incentives in order to raise the investment level in those frontier areas.

Some countries had been successful in applying tax consolidation. Thirty-one countries had already applied tax consolidation in their petroleum ventures, including United Kingdom, Norway, France, Germany, Denmark, Netherlands, Nigeria, Congo, Ghana, Australia, Brunei, China, India, Papua New Guinea, Thailand, Philippine, Turkey, Argentina, Canada, USA, Mexico, Peru and others. As an example UK, after applying tax consolidation in 1983 as part of their tax reform; realized a rapid recovery from severe drilling slump in 1978-1981 and enjoyed increased discoveries, which added an average of one billion barrels per year oil reserves through 1992 (IPA, 1995:4). Moreover, as already noted earlier, several writers also suggested applying tax consolidation to attract exploration investment in Indonesia’s frontier and deep-water areas. Therefore risk analysis of the application of tax consolidation on the GOI income and profitability of contractor as well as quantifying the risk involves respectively was needed be taken.

2.3.1.2. Risk, Uncertainty and Risk Analysis

The presentation of the risk analysis theoretical and methodology framework background was condensed from the work of Murtha (1995, 1997), Crystal Ball (2005) and others. Uncertainty and risk refer to the outcomes and their implications of some future event. In casual discussion, they are often used interchangeably, but they have very different technical meanings. Risk is the chance of injury, damage, or loss; the degree of probability of loss; or the amount of possible loss. Risk will be reserved to describe the potential gains or losses associated with particular outcomes. While uncertainty is the quality or state of being uncertain, lack of certainty, doubt. Uncertainty will describe and refer to the range of possible outcome (Murtha, 1995).

Because risk is linked with probability, risk can be accommodated through the purchase of insurance or hedging. For example, we do not know if we will be in an automobile accident next year, however, since the probability of being in an accident is known, to protect against that unfortunate outcome we can buy insurance.

On the other hand uncertainty is the lack of knowledge concerning the probability distribution of future events. Insurance is unavailable to protect against negative outcomes. Therefore, it is essential that the analyst must incorporate uncertainty into their analysis and that the decision maker incorporates uncertainty into the decision process. A lack of knowledge does not prevent making assumptions concerning potential outcomes that should be taken into consideration. Even so, uncertainty is an element of almost all decision process.

Most people desire low risk, which would interpret to a high probability of success, profit, or some form of gain. The more you know about the potential risks, the better you can deal with them. Almost any change, good or bad, includes some risk. Once the risks have been identified, a model can help you quantify the risks. Quantifying risk means putting a value or price on risk, to help you decide whether a risk is worth taking. Risk analysis is any form of analysis that studies and attempts to quantify risks associated with an investment. The general objective of risk analysis is describing the range of possible outcome and their consequences. Risk analysis is a future-oriented activity, which is trying to forecast or predict events yet to come. One of the main reasons for this activity is to compare alternative investments (Murtha, 1997:37).

Much of risk analysis consists of estimating something with range of values rather than with a single value. As example, instead of the single point estimate of 34 million USD, it is better reported that the NPV of a petroleum project is a normal distribution with a mean of 34 million and a standard deviation of 1.7 million USD.

Typically random variables are used to describe future events whose outcomes are uncertain. Random variable is any variable that has a probability distribution frequency (PDF) or a cumulative distribution frequency (CDF) that defines it. PDF and CDF of A is graph that tells about how the values of A are distributed. Histogram to describe a set of a number of values after we group the data into non-overlapping classes, such as approximating a PDF may suggest a type of distribution, a shape of PDF. There are two rules of PDF: first the scale on x-axis tells the range of values of the variable and the height of the curve tells how likely the values on the x-axis are to occur that the total area under the PDF is 1.00. Second the area under the curve between x = a and x = b is the probability that x lies between a and b.

While the corresponding CDF for given PDF is obtained by a cumulative process, just as CDF was defined for histograms. Two rules for CDF: first the CDF curve ranges from 0.0 to 1.0 on the vertical scale and from minimum to maximum value of X, so the curve is monotonically non-decreasing. Second, the value on the Y-axis corresponding to X = a, is the probability that X is less than or equal to a.

Some types of PDF widely applicable in the oil and gas industry (Figure 2.13), such as (Murtha, 1995 and Crystal Ball, 2005):

a) The Normal Distribution PDF. The normal distribution describes many natural phenomena such as IQ's, people heights, inflation rate, or error in measurements. It is a continuous probability distribution. The parameters are mean and standard deviation. There are three conditions underlying normal distribution: first some value of the unknown variable is the most likely (the mean of the distribution); second the unknown variable is can as likely as above or below of the mean (symmetrical about the mean); and third the unknown variable is more likely to be close to the mean than far away.

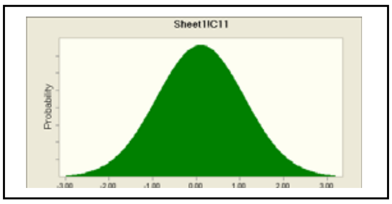
b) The Triangular Distribution PDF. In some sense, the triangular distribution is merely a simple description of variable, which is more likely to attain values near its mode than near the extremes. It is a continuous probability distribution. The parameters are the minimum, the most likely and the maximum. There are three conditions underlying the triangular distribution, the minimum and the maximum number of items must be fixed and the most likely number of items falls between the minimum and maximum values, forming a triangular shape of distribution.

c) The Uniform Distribution is completely specified by giving its minimum and maximum value. There is no mode for the uniform distributions and the median equals the mean. In the uniform distribution, between the maximum and minimum are equally likely to occur. It is a continuous probability distribution. The parameters for uniform distribution are maximum and minimum. There are three conditions underlying uniform distribution, the minimum value is fixed, the maximum value is fixed and all values between minimum and maximum are equally likely to occur.

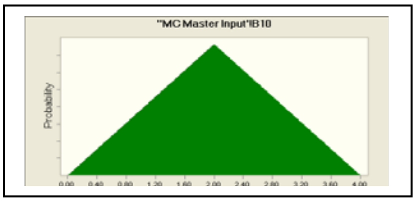
d) The Binomial Distribution PDF is an example of a discrete distribution. A random variable X that is binomially distributed counts the number of successes in n independent trials where p is the probability of success on each trial. When $p = ½$ the binomial distribution is symmetric.

e) The Lognormal Distribution PDF. It describes variables, which are highly skewed to the right, which mean that large values of X have much smaller probability than values of X in the opposite direction. It is a continuous probability distribution. The parameters are mean and standard deviation. There are three conditions underlying lognormal distribution, the unknown variable can increase without bound, but is confined to a finite value at the lower limit; the unknown variable exhibits a positively skewed distribution; and the natural logarithm of the unknown variable will yield a normal curve.

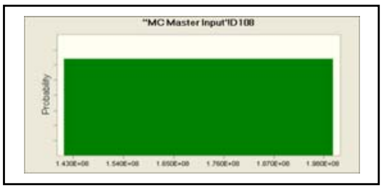
f) Pareto Distribution is widely used for the investigation of distribution that associated with such empirical phenomena such as city population size, the occurrence of natural resources, the size of companies, personal income, stock price fluctuations, and error clustering in communication circuit. It is a continuous probability distribution. The parameters are location and shape.



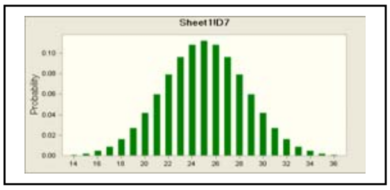
(a) Normal Distribution



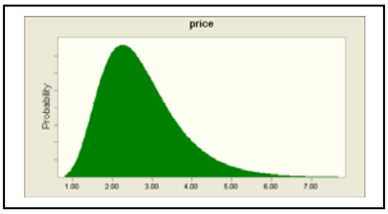
(b) Triangular Distribution



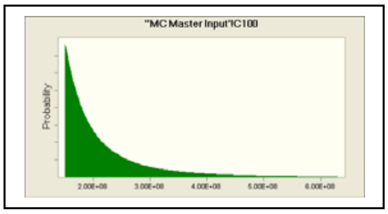
(c) Uniform Distribution



(d) Binomial Distribution



(e) Log Normal Distribution



(f) Pareto Distribution

Figure 2.13: Some type of Probability Distribution Frequency

2.3.1.3. Risk Analysis Using Monte Carlo Simulation

As already mentioned above, risk analysis is a future-oriented activity that studies and attempts to quantify risks associated with an investment. One method to carry out the risk analysis is using Monte Carlo simulation. This simulation was initially developed during the World War II by researchers in Los Alamos National Laboratory during their experimental work to estimate the probability of a neutron that would cause fission chain reaction. The method was named Monte Carlo for its similarity with roulette game, a simple random number generator.

Monte Carlo is a technique to calculate the uncertainty in a forecast of future event. It is effective in assessing risk and modelling uncertainty. Monte Carlo simulation allows us to replace uncertain quantities in spreadsheet models with reasonable estimates ranges and then see more accurately how that uncertainty affects the outcome of the model. It provides information concerning the best and the worst-case range of outcomes or probability of reaching specific targets.

This simulation involves approximation of the distribution of possible outcome of certain combinations of random variables, of which each has its own probability distribution function, by means of statistical sampling. This method is often used when the model is complex, non-linear, or involves more than just a couple uncertain parameters. A simulation can typically involve over 10,000 evaluations of the model, a task that in the past was only practical using super computers.

At each trial, the method will sample the distribution of each variable randomly and then calculate the outcome. As the number of trials increases, the distribution of experiment results will approximate the probability distribution function of the outcome. This distribution of the outcome will cater to questions such as the likelihood a certain project will generate NPV more than 100 million USD, a certain reservoir has 90% chance to have oil in place bigger than 100 million STB and others. These kinds of answers will help in assessing the risk of certain outcome.

Figure 2.14 shows an example of an application of Monte Carlo simulation to estimate a simple equation of F = X*Y. At each trial, the distribution function of the input parameters X and Y are sampled, the realizations of X and Y of the trial are then multiplied to calculate F. The trial process is then repeated multiple times, if the number of trials is sufficient enough then histogram of the trial results is the approximation of the distribution function of F.

The strength of Monte Carlo simulation are its universal applicability, the result contains maximum information about possible outcomes and the methods itself leads to sensitivity analysis. While the advantages of the simulation are: first the full range of each uncertain input parameter can be sampled and used in generating the probabilistic model outcome. The second advantage is easy to implement, any input-output model can be utilised in the Monte Carlo process without making any modifications to the original model. While the third advantage is that the Monte Carlo approach is conceptually simple and easy to explain.

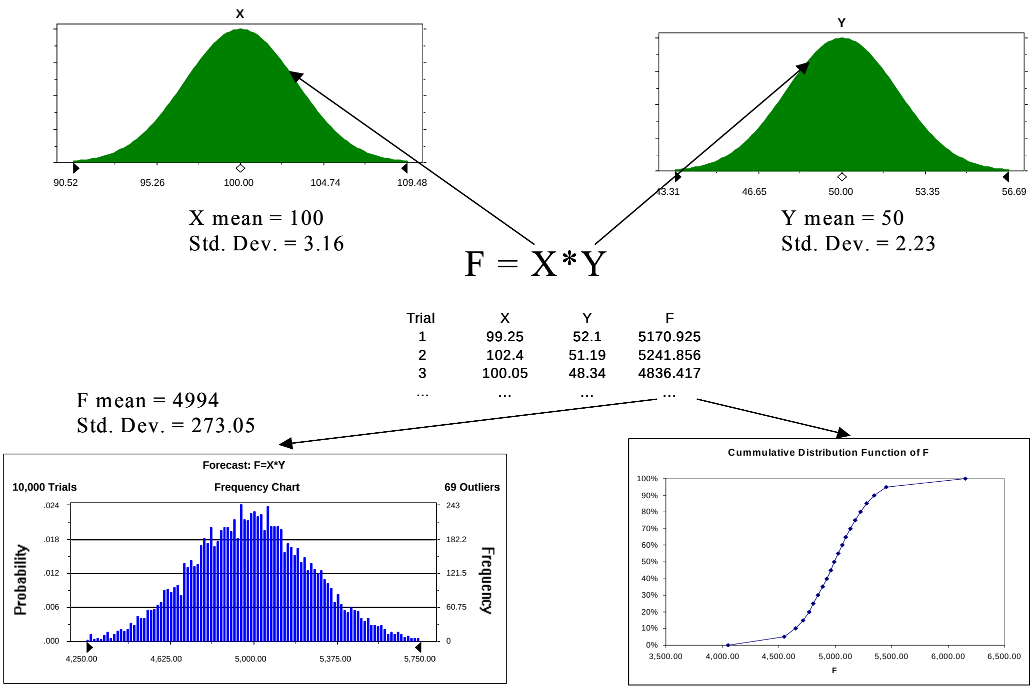


Figure 2.14: Schematic Example of Monte Carlo Simulation

Monte Carlo simulation starts with development of a model, i.e., one or more equations, together with assumptions and logic relating the parameter in the equation. After the model was developed, the second step is determining the influencing factors/variables, which may cause the largest affects against the outcome. Then to analyse and identify the inter relationship between each factors. This procedure was done by either using expert opinion or historical data information.

The third step is to determine the input values for each variable above to apply it in the model. The input values for variables above are in distribution form. Therefore, determining the most suitable distribution for each variable based on historical information or expert opinion has to be done. Lognormal distributions are often used for many of the volumetric model input, while triangular distributions are also fairly common and are easy to adapt because they can be symmetric or skewed either left or right. In the case there are sufficient historical data, then these data can be used to determine the suitable distribution. Expert opinion is only used to determine the distribution in the case there are not enough information available. The fourth step is run the model using Monte Carlo software to shape the probability distribution of the outcomes. Sensitivity analysis the will be drawn as the final step (Murtha, 1997:2-3).

Back to petroleum E&P venture, given this venture characterised as high risk and uncertainty venture. Meanwhile the operation faces complex situation due to their multiple phases of their operation where the production phase depends on the outcome of the exploration phase; the uncertainties on the existence of the resource, the volume of reserves in each discovery, and on the level of production are not specified in the contract as well as the costs vary and technology used; the price vary and the uncertainty of the product (oil only, oil and gas or gas only) respectively. Therefore investment decision-making in this venture faces complex situation. As example due to its uncertainties, it is difficult to choose the accurate assumptions to forecast the profiles of input variables of the model such as production, cost, price and others in doing the cash flow analysis.

As already mentioned earlier, under Monte Carlo simulation each input variable has its own probability distribution and the probability distribution of the outcome will cater to questions such as the probability a certain project has 80% chance will generate NPV more than 100 million USD and other. Moreover this method often used when the model is complex, non-linear, or involves more than just a couple uncertain parameters. It also has many advantages and strength as already mentioned earlier, such as easy of implementation and conceptually simple and others. These facts imply that this method is appropriate to be used in making risk analysis in petroleum E&P venture.

This method already used by the Indonesian Petroleum Association (IPA, 1995) in investigating the impact of tax consolidation. The IPA ran a simple Monte Carlo simulation model of the application of tax consolidation in Indonesia with scenario and assumptions applied as seen in Table 2.9. The input variables were total well drilled per year, operation years, tax rate, exploration expenditures, development expenditures, oil price, the chance of commercial discovery reserves, the distribution of commercial reserves size. The model used was the PSC3 with IP4 terms and variables.

Table 2.9: Scenario, Assumption and Result of IPA's Monte Carlo Simulation on tax consolidation application in Indonesia (IPA, 1995:app. II)

No	Items	Assumption	Remarks
1	Total drilling wells per year	50 wells	Represent the difference between historic level of 125 wells per year and the current level 75 wells per year
2	Total exploration spending increased per well	11 millions USD per well in 1994 USD	Totally 550 millions per year, it is equal to the average level of total exploration per wildcat well during period 1983 - 1991
3	Tax rate	48%	GOI maximum cost of 264 millions USD and contractors of 282 millions USD per year in 1994 dollar
4	Period	10 years, 1996 - 2005	Long enough to give a representative answer but manageable for calculation
5	Oil price	Constant at 17 USD/barrel	
6	Escalation for cost and price	4%	
7	Discount date and discount rate	1/1/1996 and 10%	
8	PSC	1993's Incentive Package	Profit split 65/35, no investment credit, FTP of 15% and DMO price of 25% of market
9	Distribution of activity by play type	Shallow water 60% Remote Onshore 30% Deep water 10%	Reflects the relative economics and cost of exploring in different environments
10	The distribution of reserve size if commercial discovery is made	50 MMB 80% 150 MMB 15% 450 MMB 5%	Consistent with historic trends in Indonesia
11	The chance of commercial discovery from given well	5%	Consistent with historic results in Indonesia
12	Result of analysis after simulation ran 10 times	Mean GOI's IRR: 26% and NPV@10%: 3,114 million USD	GOI spending per year 1% of total GOI revenues or 3.8% of GOI oil & gas revenues in 1994

Total well drilled per years are assumed 50 wells per year with the cost 11 millions per well (average level of total exploration per wildcat well during period 1983 – 1991), totally 550 millions per year. Operation year was set up 10 years. Tax rate assumed 48%, hence the GOI maximum expenditures cost of 264 millions USD and contractors of 282 millions USD per year. The oil price was set up at 17 USD per year escalated at 3% per year. The chance of commercial discovery was 5%, and distribution of commercial reserves size were set up at 50 MMB of 80%, 150 MMB of 15% and 450 MMB of 5%. While the play type were set up at shallow water of 60%, remote onshore of 30% and deep water of 10%.

The simulation ran only 10 times. The result of tax consolidation application in Indonesia during ten years period 1996 – 2005 showed good long-term economics to the GOI. The average IRR of the GOI was 26% and cumulative cash flow over ten-year period was 14 billions USD. While in the short time the GOI lost only around 1% of its total revenues or only 3.8% of oil and gas GOI revenues in 1994.

The IPA analysis only analysed from the view of GOI, it did not quantify the risk involved for both parties, did not the impact on contractor's revenues, did not compare its impact with increasing the production sharing split, the period of analysis only 10 years, the number of running was too low only 10 times, and some other assumptions were needed to be concord. Higher trials statistically could give better results and smoothen the distribution lines. Therefore analysis to investigate the impact and risk involve of tax consolidation application especially in Indonesia frontier areas on the GOI income and profitability of contractors and compares with the increasing the production sharing split with assumptions almost matched with recent Indonesia's conditions was considered be done. Monte Carlo simulation was chosen be used in this risk analysis.

2.3.2. Identifying the Companies' Views with Respect to the Most Desirable Petroleum Contract System

2.3.2.1. The Need for Identifying the Companies' Views with Respect to the Most Desirable Petroleum Contract System

The uncertainties in petroleum E&P venture lead to different perceptions by interest parties (petroleum companies and host governments). The perception of each player is a function of its information, effort, expertise and experience. Different perceptions will lead to different contractual relationships and different allocation of risks and rewards between the contract's parties (Abadeer (1993:8). Moreover experiences and knowledge might result differences in perceptions, feelings and judgments about something subject. While environment conditions changes might also changes the experiences. The contractor's experiences and knowledge in doing petroleum E&P business as well as changes in the business environment in Indonesia could change their perception, feelings and judgments about them, including their judgment about the benefits, the costs and the risks of the petroleum E&P operation in Indonesia. Thus contractor's experiences, expertise and the Indonesia's geological potential, economic, social and political conditions changes might change the contractor's view, which is the most desirable petroleum contract system that match with those conditions.

Risk capital is being more scarce and competitive; many changes on Indonesia's economic, social and political conditions occurred; and spectacular changes of world oil prices as mentioned earlier made the competitiveness of the Indonesia's petroleum venture decreased and the bargaining position of Indonesia reduced. Moreover the remaining basins (proved reserves, unproved reserves and have not been drilled) have been found largely in eastern part of Indonesia, deep water and frontier areas that have higher risks and costs. One of many other alternatives can be done in order to attract petroleum E&P investment is offering the petroleum companies' desirable petroleum contract system. That is why GOI needs to understand the petroleum companies' views with respect to the most desirable petroleum contract system.

2.3.2.2. The Analytic Hierarchy Process

Making decision in complex situation whenever both objective and subjective factors are present is not easy. Analytic Hierarchy Process (AHP), a well-known method for solving complex decision-making problems can be applied (Alford, 2004: 4). The AHP is described by Saaty and Kearns (1985:19) as a

> "… systematic procedure for representing the elements of any problem, hierarchically. The AHP organises the basic rationality by breaking down the problem into its smaller and smaller constituent parts and then guides decision makers through a series of pairwise comparison judgments (which are documented and can be re-examined) to express the relative strength or intensity of impact of the elements in the hierarchy. These judgments are then translated to numbers. The AHP includes procedures and principles used to synthesize the many judgments to derive priorities among criteria and subsequently for alternative solutions"
>
> (Saaty and Kearns, 1985:19)

This method has already been applied to wide range of complex decision problems. Some examples are: developing public strategy (Saaty, 2000:10-11); developing business strategy (Kintarso and Peniwati, 2001: 1-7, and (Hummel JM, et al, 2001: 41 – 64); design and the development of new product (Kengpol and O'Brien, 2000:1-4; and Hummel JM, et al, 2001: 72 – 144); a post evaluation of a project (Azis I.J., 1989: 38 - 48); technological assessment (Hummel, 2001: 1 – 14); designing inter-organizational communication (Hummel JM, *et al*, 2001: 18-36); project risk management (Mustafa and Al-Bahar, 1991); decision-support system in the petroleum pipeline industry (Nataraj, 2005); prioritisation methods for defence planning (Nguyen, 2003); priority setting in agriculture biotechnology research (Braunschweigh, 2000); conflict resolution (Saaty, 2000:10); human resources allocation (Saaty and Peniwati, 2000); determining the best sport record (Alford, 2004: 1-99); and many others. However, no application of AHP has been reported in the literature for choosing the desirable petroleum E&P contract system on the view of petroleum company. Below, the basic principles and steps in the AHP are described, followed by an explanation of its theoretical basis that was condensed from many sources as mentioned above.

The AHP method is developed based on some fundamental facts and thoughts that first human minds can value two different objects comparatively. Second human mind is inconsistent, but a well-informed people will have a rationale mind, its philosophy is *it is better to be approximately right than precisely wrong*; this method leads to a limit of 10% inconsistent level. Third the most accurate way to draw priorities of the objects is pair wise comparisons. AHP is created based on *objectivity is agreed upon subjectivity;* therefore qualitative data must be transformed to quantitative data in order to draw a consistency (Peniwati, 2000:2).

There are three steps in decision-making involving AHP: first decomposition of a complex unstructured problem and then structured them into a hierarchical structure that shows the problem's key elements and their relationship; second comparative judgment about its element by making pair wise comparisons; third synthesis of priorities derived from the judgment with respect to the overall goal. The software package called *Expert Choice* incorporates the AHP methodology and enables the analyst to structure the hierarchy and solve the problem through pair wise comparisons using relative or absolute measurement.

The first step is breaking down the decision problem into a hierarchical structure. Building the hierarchy structure is the most challenging of the three steps in the AHP (Alford, 2004:5). The hierarchy structure starts at top level that states the overall goal of the decision making from the decision maker viewpoint. Followed directly beneath this goal are the main criteria to be considered when making decision. For greater precision, the criteria may be divided into sub criteria, creating an additional in the hierarchy.

Figure 2.15 shows a general three level hierarchy structure. The overall goal can be seen in top of the hierarchy and is broken into four key criteria that directly influence the goal above them. In general, there is no limit to the size and number of levels within the hierarchy, can be two or three levels of criteria and sub criteria or more. In this simple example there is only one level. The bottom level states a list of alternatives that could solve the problem. Hierarchy structure is said to be complete when every element of a given level functions as criteria for all elements of the level below.

After a hierarchy as the representation of the problem has been realised, then it is followed by the second step: evaluating the alternatives and weighting the criteria. The alternatives are compared in pairs (pair wise comparison) to access their relative performance with respect to each criterion. People already intuitively reduce complexity by using these pair wise comparisons (Hummel JM, et al, 2001: 45). With the same procedure, the criteria are compared in pairs to define their importance with respect to the overall goal. The comparisons are based on hard data, as well as on intuition, experience, and expertise of the participants. That is why AHP explicitly allows for subjective judgments and recognizes their legitimate role in ex ante analysis (Braunschweigh, 2000:33).

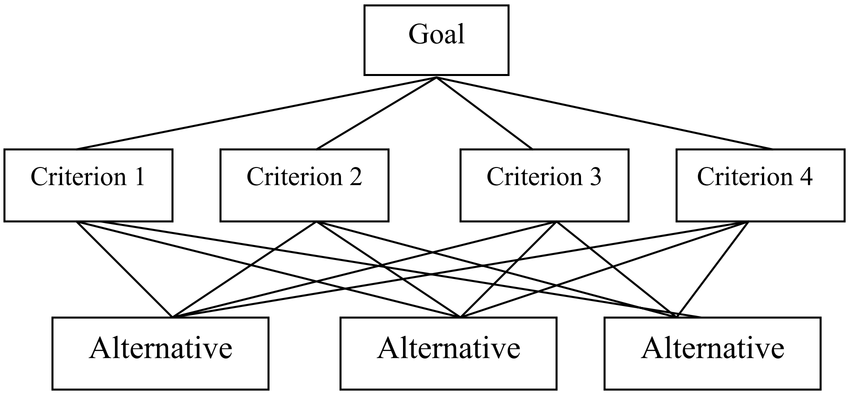


Figure 2.15: A General Three Hierarchy Structure

The Fundamental Scale as seen in Table 2.10 is used to elicit the comparisons. This scale was derived from the basic mathematics of neural firing that leads to a well-known logarithmic law of stimulus response, and has been validated for effectiveness, not only in many applications but also compared with other scales by applying it in real life situation where measurements are already known. The numbers are used to represent how many times the larger of two elements dominates the smaller one with respect to a property or criteria they have in common.

The use of verbal comparisons facilitates the weighting of criteria, as well as evaluation of alternatives in terms of non-quantifiable criteria. Once these verbal comparisons are made, they are translated into the numerical values of the fundamental scale. After the entire pair wise comparisons were already done, and then a set of *local priorities* will be generated, which express the relative impact of the set of criteria on an criterion in the level immediately above. The relative strength, value, worth, desirability will be found, or probability of each of the items being compared by solving the matrices, each of which has reciprocal properties. In this case a set of eigenvectors need to be computed for each matrix and then the result was normalized to unity to obtain the vectors of priorities.

Table 2.10: The Fundamental Scale (Saaty, 2001:28)

Intensity of Importance	Definition	Explanation
1	**Equal Importance**	**Two activities contribute equally to the objective**
2	Weak	…. Between Equal and Moderate
3	**Moderate importance**	**Experience and judgement slightly favour one activity over another**
4	Moderate plus	…. Between Moderate and Strong
5	**Strong Importance**	**Experience and judgement strongly favour one activity over another**
6	Strong plus	…. Between Strong and Very Strong
7	**Very Strong or demonstrated importance**	**An activity is favoured very strongly over another; its dominance demonstrated in practice**
8	Very, very strong	…. Between V. Strong and Extreme
9	**Extreme importance**	**The evidence favouring one activity over another is of the highest possible order of affirmation**
Reciprocals of above	If activity *i* has one of the above nonzero numbers assigned to it when compared with activity *j*, then *j* has the reciprocal value when compared with *i*	If x is 5 times j, i.e., x = 5y, then y = x/5 or y = 1/5 x.
Rationales	Ratios arising from the scale	If consistency were to be forced by obtaining *n* numerical values to span the matrix.

Figure 2.16 shows the type of matrix used to enter the pair wise comparisons. As example, the comparison of alternative 1 with alternative 2 yields the value a_{12}. For obvious reasons, the diagonal cells always contain the value 1. Due to the judgments may not be consistent; therefore the eigenvector method described below is used to compute these values.

	Alternative 1	Alternative 2	Alternative 3	Local Priority
Alternative 1	1	a_{12}		
Alternative 2		1		
Alternative 3			1	

Figure 2.16: Matrix to derive local priorities

The third step was synthesising the local priorities throughout the hierarchy, in order to compute the global priorities of the alternatives,. The principle of hierarchic composition is, for each alternative, the local priorities are multiplied by corresponding criterion weight, and the results are summed up to obtain the global priority of the alternative with respect to the overall goal stated in the top level. Thus the equation (Braunschweigh, 2000:34):

$$A_l = \sum_{m=1}^{M} A_{lm} V_m \qquad \text{with} \sum_{l=1}^{L} A_{lm} = 1 \qquad \text{and} \qquad \sum_{m=1}^{M} V_m = 1$$

where:

A_l : final priority of alternative 1

A_{lm} : priority of alternative l with respect to criterion m

V_m : weight of criterion m

l : (1,……., L)

m : (1,……, M)

Basically pair wise comparison uses matrix form, it is a square form in which an array of numbers is arranged. When a set of elements (criteria or alternatives) of problem are compared with each other, a square matrix is given as:

$$A = \begin{pmatrix} a_{11} & a_{12} & a_{13} & \dots & a_{1n} \\ a_{21} & a_{22} & a_{2} & \dots & a_{2n} \\ \dots & \dots & \dots & \dots & \dots \\ a_{n1} & a_{n2} & a_{n3} & \dots & a_{nn} \end{pmatrix}$$

This matrix has reciprocal properties, that is:

$$a_{ji} = 1 / a_{ij} \qquad \text{for all } i,j = 1, 2, \dots n$$

A vector of weights or priorities $w = (w_1, w_2 \dots w_n)$ is computed. Note that by using ratio scales, the estimated weights are only unique up to multiplication by positive constant. Thus w is equivalent to cw where $c > 0$. For simplicity, usually w normalised so that it adds up to 1 or 100. When the judgments were perfectly consistent, i.e., $a_{ik}a_{kj} = a_{ij}$, then the entries of the matrix A would contain no errors, and could be expressed as $a_{ij} = w_i / w_j$. Note that

$$a_{ik}a_{kj} = w_iw_k / w_kw_j = w_i\ w_j = a_{ij} \quad \text{for all } i,j,k = 1,2,\ldots,\text{n}.$$

In this case the last result can be drawn by simply normalise any column j of A to yield the final weights:

$$w_i = a_{ij} \ / \sum_{k=1}^{n} a_{kj} \qquad \text{for all } i = 1,2,\ldots,\text{n}.$$

Yet, errors in judgment are common, so the final result using column normalisation would depend on which column is chosen.

Saaty (1985) recommends the eigenvector method for estimating the weights when there are errors in judgment. The method computes w as the principal right eigenvector of the matrix A:

$$Aw = \lambda_{max}\, w,$$

Where λ_{max} is the maximum eigenvalue of the matrix, or

$$w_i = \left(\sum_{j=1}^{n} a_{ij}\, w_i\right) / \lambda_{max} \qquad \text{for all } i = 1,2,\ldots,\text{n}.$$

The eigenvector method is a simple averaging process by which the final weights w is computed as the average of all possible ways of comparing the alternatives.

Actually the result the matrix does not have perfected consistent, due to someone does not have consistency of preference. In matrix theory, in the case little wrong on coefficient could result a little inconsistency of eigenvalue. With combination what are discusses above, if the value of the matrix A is one and A is consistent, then a little inconsistency from aij still has maximum eigenvalue λmax, and the value is near to n and the other eigenvalue near to zero. The inconsistency of matrix could be shown from Consistency Index (CI), with equation:

$$CI = (\lambda max - n) / (n - 1)$$

where : λmax = maximum eigenvalue

n = the matrix size

For each size of matrix n, random matrices are generated, and their mean CI value, called the random index (RI), is computed. According to the Saaty on his calculation with 500 samples, if numerical "judgment" in random from scale 1/9, 1/8, … 1, 2… 9, then it could give consistency average of matrix as stated in Table 2.11. The comparison between CI and RI of a matrix be defined as Consistency Ratio (CR)

$$CR = CI / RI$$

In the AHP, the matrix comparison could be used if the value of Consistency Ratio (CR) $\leq$ 0.1. This allowing with inconsistencies is a major strength of the AHP (Hummel JM, et al, 2001: 45).

Table 2.11: Matrix size vs. Random Consistency

Matrix Size	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Random Consistency	0.00	0.00	0.58	0.90	1.12	1.24	1.32	1.41	1.45	1.49	1.51	1.48	1.56	1.57	1.59

2.3.2.3. Choosing an Appropriate Method

As already discussed in section 2.1.2, in the entire phases of petroleum E&P operation, from exploration, development and production phase petroleum company faces uncertainties and risks, from geological, costs, technological, price, fiscal, contract to political risk and others. When it fails to discover commercial discovery, the petroleum company bears all the risks. In the case it discovers commercial petroleum production; it gets benefit as the result of their activities. Due to many aspects influencing the petroleum E&P operation above, in identifying the petroleum companies' views with respect to the most desirable contract system that could attract petroleum companies to invest in petroleum E&P venture in Indonesia is complex and have multiple criteria both physical / objective and psychological / subjective aspects.

In his research about priority setting in agricultural biotechnology research, Braunschweig (2000:26-32) compared the AHP method with four other methods that have been developed for establishing research priorities; they are scoring, cost-benefit analysis, mathematical programming, and simulation models. He defined priority in research is the process of ranking different research alternatives, while decision making is the process of choosing a set of alternatives.

In scoring model, criteria that reflect the objectives of the subject are defined and weighted by decision makers, and then the alternatives are scored according to each criterion by using a discrete scale. These scores are then multiplied by each criterion weight. The ordinal ranking of alternatives can serve as a basis for allocation. Several advantages of scoring model are it relatively easy to apply, it facilitates the integration of multiple objectives and the model can cope with both qualitative and quantitative criteria.

While cost-benefit analysis usually utilize the concept of economic surpluses, whether explicitly or implicitly. Supply and demand curves in market framework can be used to explain its basic principles. Technology innovation generated by research will shift the supply curve to the right. This shift denotes benefits that can be measured as net changes in consumer and producer surpluses. To calculate the net benefit, the benefit compared with the cost, which the estimation can be expressed as an IRR, NPV or a cost benefit ratio. To accommodate uncertainty, expected values need to be estimated based on different assumptions or probability distribution. Cost benefit analysis method is useful for estimating the economic consequences of different research activities. The limitation of this method is all costs and benefits are expressing in monetary terms only.

Mathematical programming is an optimisation for guiding the allocation of limited resources. The basic approach is to formulate an objective function that is maximised subject to certain constraint, such as funding, human resources or institutional capacity. Mathematical programming can be used to illustrate the trade offs among objectives and to analyse the implications of changing constraints. May be due to the considerable analytical skill required for proper formulation of the model, time consuming process (the effort needed to collect and process data is similar to that required of benefit-cost and scoring models plus additional time needed to design, test and run the model), only a few application of programming method are reported in the literature.

Simulation models are based on principles of production economics. They estimate the functional relationship between input (such as research investment) and output (such as agriculture production). Through modelling the agriculture production sector or part of it, simulation model usually operate on a higher aggregate level. A production function may be used to represent the econometric relationship between agriculture productivity and research expenditures and additional determining factors. The effects of various research expenditures on productivity are simulated and translated the result into a supply curve shift that illustrated its economic consequences. Simulation models are very flexible and can be used to analyse the wider impact of research investments, but the process need substantial time and skill for collecting the detail data and determining the mathematical relationship to build the model and the econometric relationships is based on time series data that are not readily available.

With respect to three key requirements i.e. participation, transparency, and a standardised measurement procedure, Braunschweig evaluated those methods above. Under cost benefit analysis, mathematical programming and simulation models all place analyst at the centre of priority setting process, consequently these models have a low potential for active participation. Methodological complexity of simulation models and mathematical programming results in poor transparency, while cost benefit analysis and scoring model are fairly transparency, due to those two models the process of generating the model is easily understood. Cost benefit analysis focuses on the economic impact of the research, simulation models can take into account a wider range of research effects, but they do not provide ranking of research project. Both mathematical programming and scoring models can incorporate many different effects, including qualitative effects. Braunschweig concluded that among four models only scoring model fits all the requirements imposed by complexity of biotechnology decision making, however the different methods are not mutually exclusive, such as the outcome of a benefit cost analysis could used as input for scoring model, or a simple integer programming approach could be used to allocate the resources based on the priorities generated by the scoring model. However the scoring model has limitation, i.e. its high cost due to the considerable amount of time needed for scientist and other participants in the process, and the absence of a sound theoretical framework. Another limitations are based on the lack of theoretical basis of scoring model, there is no procedure to prevent double counting due to overlapping criteria, to translate the differently measured (quantitative) impact and verbally expressed (qualitative) impact into meaningful scores to aggregate the scores across all these criteria, taking into account their different weight. The AHP has the potential to overcome this deficiency (see subsection 2.3.2.1). Therefore in his research Braunschweig used the AHP method.

To identify the most desirable petroleum contract system is analogue with priority setting that had been done by Braunschweig above. In his study, Braunschweig made a priority setting the alternatives of agriculture biotechnology research, while this study made priority setting the alternatives petroleum contract system. Moreover Nguyen (2003) also succeeded in using AHP in prioritisation methods for defence planning. Looking at the advantages of the AHP method mentioned above, this study valued that AHP method in the benefit-cost-risk framework was appropriate to identify the petroleum companies' views, which is the most desirable petroleum contract that is suitable with the current Indonesia's geological potential as well as the economic, social and political conditions respectively.

2.3.2.4. Developing the Model for Identifying the Companies' Views with Respect to the Most Desirable Petroleum Contract System

Any decision has several favourable and unfavourable concerns to consider. The favourable impacts are called the benefits and the unfavourable impacts are called the costs. The uncertain concerns of a decision are the positive opportunities that the decision might create and the negative risks that can entail (Saaty, 2001:93).

Saaty suggests the use of separate hierarchy for these three concerns, the benefit hierarchy structure, the cost hierarchy structure and the risk hierarchy structure, with the same alternatives on the bottom level of each. Hence one obtains three priority vectors, a benefit priority vector, a cost priority vector and a risk priority vector. The weightings of benefit, cost and risk criteria were calculated through the comparison of the mean score of each combination of the benefit criteria, the cost criteria and the risk criteria. Then the *(benefit / (cost x risk)* vector is obtained with the highest ratio indicating the preferred alternative (Saaty, 2001:43).

The first step of the analysis was to set up the goal of the AHP analysis. The goal was to identify the most desirable petroleum contract system in the views of petroleum companies that could attracts petroleum companies to invest in upstream petroleum E&P venture in Indonesia.

As already noted earlier, the decision-making process in investing money in petroleum E&P faces complex situations; it does not only depend on geological potential but it also depends on many uncertainties and risks. To achieve successful petroleum E&P investment, prior to bidding and negotiating a petroleum contract, petroleum company would take several analyses carefully a number of elements into account and evaluate them under different scenarios such as geological potential, variation of petroleum prices, costs, technology needed, contract terms, risks of the prospect and others. The objective is to maximise revenues in each scenario.

When a petroleum company works as a contractor for the national owned company or government agent on behalf of the host government, due to total profit must be shared between the petroleum company and the host government, then the petroleum company be entitled to receive the petroleum company's share of profit and the cost recovery. As the share of profit comes from production multiplies price, while production profile can be search from the geological potential of the basin/area/country be offered. A rise in geological potential of the basin/area/country means the higher the opportunity to get the benefit and the higher return of investment might be, and possibly could yield higher attractiveness on investment opportunity.

The geological potential could be estimated based on criteria: reserves (R) include two aspects remaining discovered reserve and estimate undiscovered reserve, total reserve addition (TRA), current production (CP) and reserve to production ratio (R/P). As shown in Table 2.12, the reserve (R) is defined as reserves that has already been discovered but has not been produced (remaining discovered reserves) plus the potential amount of undiscovered reserves in the basin/area/field/ country. Total reserve addition (TRA) is the total reserves addition in the last several years proved as well as probable in the basin/area/field/ country. While the latest data of annual petroleum production represents the current production (CP) of the basin/area/field/ country; and reserves to annual production ratio (R/P) is the ratio between the size of reserve to the size of annual production of the basin/area/field/ country disregarding production declines or any reserve growth, it shows the number of years of future production at current production rates. Those four aspects could be joined in the Benefit Hierarchy Structure (see Figure 2.17).

Table 2.12: Definition of criteria in petroleum E&P venture

A. Benefit	
Reserves (R) proved and potential	The reserves that has already been discovered but has not been produced (remaining discovered reserves plus the potential amount of undiscovered reserves) in that basin/area/field/ country.
Total Reserve Addition (TRA)	Total reserve addition in the last several years (TRA) proved as well as probable (P+P)
Current Production (CP)	The latest data of annual petroleum production.
Reserve/Production Ratio (R/P)	Reserves/annual production ratio. R/P ratio disregards production declines or any reserve growth shows the number of years of future production at current production rates
B. Cost	
Cost Risk (CR)	Cost expenses plus increasing costs vary irregularly due to unpredicted operational issues such as unexpected side effects that decrease the quality of environment during operation; longer in contract and project approval process; legal issues; community relation; government relation; security of assets, people and ownership; manpower regulation and relation; interference from other government agencies; infrastructures; delay in operations, security and others.
Geological Risk (GR)	The possibility of failure in exploration result activity and failure in technology chosen.
C. Risk	
Price Risk (PR)	Happens because demand may go up or fall at some point in time either because of a change in demand behaviour or because of new sources of supply (market risk), and because price may vary irregularly.
Fiscal Risk (FR)	Occurs due to changes in the fiscal terms such as tax, inflation, or others.
Contract Risk (CoR)	Happens due to unpredicted revision in the contract element, confusing about the contract content or non-performance of one party
Political Risk (PoR)	Happens due to changes in the political condition, either by having a new party in power or by some type of coup, election, implementation of new regulation and others.

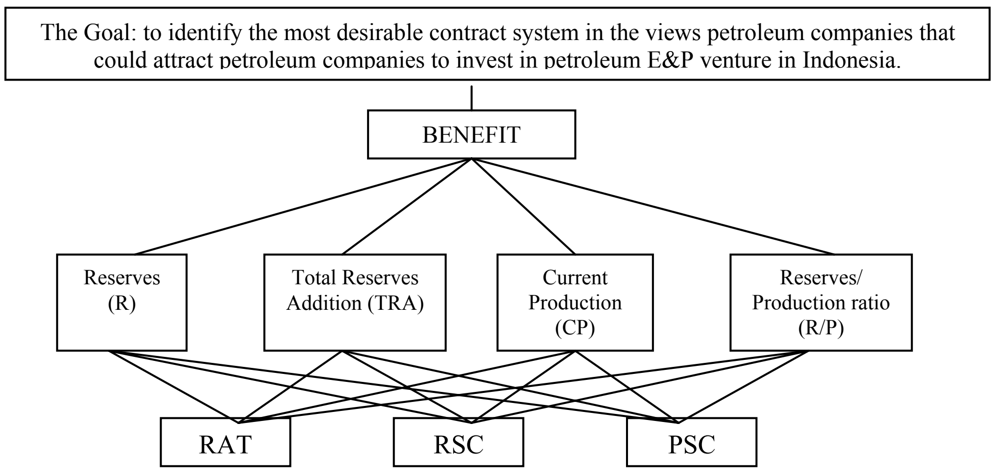


Figure 2.17: The Benefit Hierarchy Structure of petroleum E&P venture

After signed the contract, during exploration phase activities, immediately the petroleum company must expense costs for exploration activities and faces increasing costs irregularly (CR). While the chance in exploration activities to discover commercial petroleum deposit is very low, the risk associates with the probability exploration does not find a commercial deposit is known as geological risk (GR). Geological risk and cost risk will be entailed immediately in the operation, so these two aspects could be joined in the Cost Hierarchy Structure (see Figure 2.18).

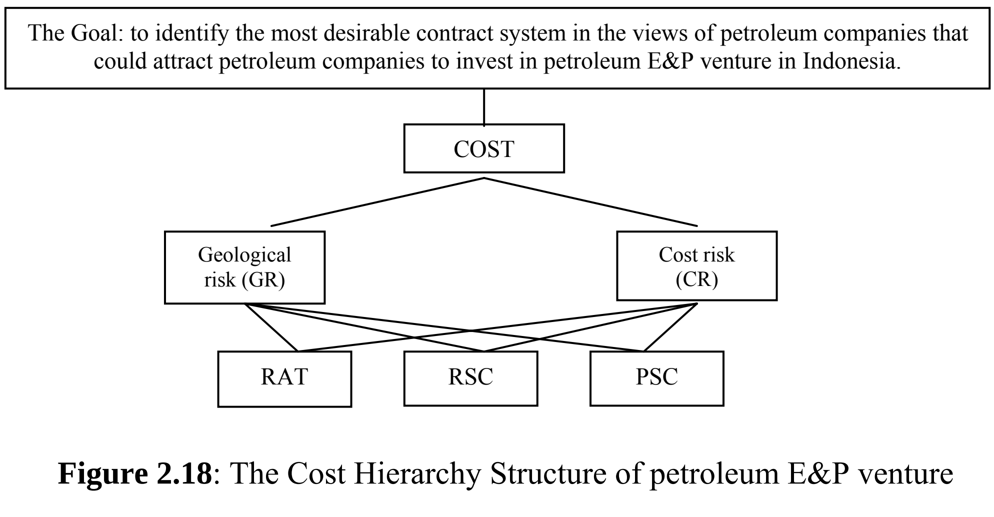


Figure 2.18: The Cost Hierarchy Structure of petroleum E&P venture

After discovery geological risks begin to diminish; in contrast price risk, market risk, fiscal risk, contract risk, political risk intensify during development and production phase of the life cycle of the venture. Price and market risk could be joined together into price risks. Those four criteria: Price Risk (PR), Fiscal Risk (FR), Contract Risk (CoR) and Political Risk (PoR) could be joined in the Risk Hierarchy Structure (see Figure 2.19).

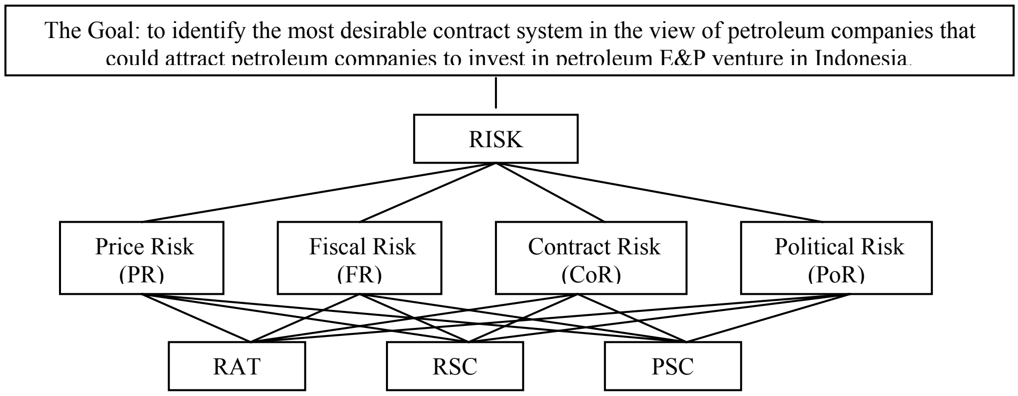


Figure 2.19: The Risk Hierarchy Structure of petroleum E&P venture

Evaluating the benefits that might be obtained in investing in E&P venture in Indonesia is done through scoring from 1 to 7 in order of its importance impact to increase the benefit stream of the venture (Note 7 is the most important and 1 is the least important) of the four criteria of the benefit hierarchy structure, with the assumption that all parameters below exist in the recent Indonesia's condition. The cost hierarchy valuation is also done through scoring from 1 to 7 in order of its importance of those two cost criteria above in making additional cost or reducing the revenue. Similar to those two hierarchy structures above, the valuation of risk also through scoring from 1 to 7 in the order of its importance of the four risk criteria in making additional risk or reducing the revenues.

As already mentioned earlier in Chapter 1 there is no standard format for any petroleum contract type categories and each may contain some of the characteristics of the other. Lan (1990: 1), Gao (1993: 10) and Johnston (1994:21-27) categorised the petroleum contract system into three main systems: concessionary or royalty and tax system (RAT), production-sharing contract (PSC) and risk service contract (RSC). In addition to three contract types above, Gao added hybrid contract that combined RAT and PSC system into one system, while Johnston (1994:21-27) added pure service contract, rate of return contract and joint venture. Joint venture and rate of return contract can utilise RAT, PSC or RSC systems. Pure service contract is rarely applied in petroleum E&P venture. Moreover Indonesian PSC has three variations, they include technical assistance contract, joint operating agreement run by a joint operating body and enhanced oil recovery contract; however, all of these types were still PSC systems (Johnston, 1994: 21-27). Meanwhile ESCAP (1984: 14 – 21) categorised taxation in mineral E&P venture into fixed fee; specific or ad valorem duty (royalty); income tax applied at higher rate than other industries; progressive profits tax; the resources rent tax and brown tax; as a variant of them; or combination of two or more of them. All of these ESCAP contract types are RAT contracts with variation of taxation.

Abadeer (1993:69-113) categorised the natural resources E&P contracts into operated by public company; service contract; cash bonus contract and RAT contract. In the RAT contracts there are 6 variants contract types, which include traditional RAT contract, royalty plus cash bonus bidding contract as well as mixed RAT contract, profit sharing contract, resources rent contract and PSC. Currently, coal-mining contract in Indonesia applies contract of work system (COW). This system is analogue to RAT system in petroleum sector, since the ownership of the resources is on the contractor side. While in agricultural sector, since a long time ago there are three main contract forms, which include direct cultivation, fixed rents tenancy, and sharecropping system. Compares to natural resources contracts, the direct cultivation is equivalent to operate by public company, fixed rent tenancy to RAT and sharecropping is equivalent to PSC (Bindemann, 1999:31).

Looking back to the petroleum industry development in Indonesia, since its first discovery until 1963, Indonesia's oil industry was operated under the traditional RAT system. In 1963 it was then changed to Contract of Work, while 1966 up to present it applied PSC system. Indonesia objected the traditional RAT system, since under the RAT system, the exclusive right given to the petroleum company was an almost unrestricted right and exorbitant privileges; the government granted petroleum company the right to explore the prospect, drill, extract, refine, carry away, export and sell the petroleum produced (Gao, 1993:29).

The development of the RAT system showed that currently this system had transformed into modern system that contained numerous fiscal devices, layers of taxation, and sophisticated formulae and others. As example, Thailand's modern RAT system was relatively generous and simple arrangement in terms of form, content and administration. In this system, beside royalty and taxes, there were a number special advantage clauses that must be provided to the government by the concessionaire, such as a government right to purchase oil on first priority basis, preference to local goods and service, signature bonus, annual bonus, domestic supply, preference for domestic services, employment and training, government participation and others.

According to Gao (1993: 71 – 112), Thailand Modern RAT system serves as a useful tool for attracting foreign petroleum companies to invest in the developing countries with unproven petroleum potential, geographically isolated exploration areas such as frontier, remote and deep-water areas, little capital, technology and others. As currently Indonesia has very weak financial capacity to invest in high-risk petroleum E&P investment and must attract investor in high-risk exploration investment in frontier areas, the modern RAT system may serve as a useful device to attract foreign direct investment in the geographically isolated exploration frontier areas. That is why beside the current PSC system, the modern RAT and RSC system are chosen as the alternatives, which will be investigated in this analysis.

Answering two questions of each comparison between two alternatives contract system drew pair wise comparisons among alternatives. As an example:

- The first question in comparison judgment between RAT and RSC under Indonesia's Reserves (R) condition is: To reach the objective of attracting investor to invest in petroleum E&P industry in Indonesia, under Indonesia's Reserves (R) condition, which is more important/desirable, RAT or RSC system?
- If the answer of the first question is that RAT is more important than RSC, then the second question is: Under Indonesia's Reserves (R) condition, how much more important/desirable is RAT over RSC (or RSC over RAT, in the case of RSC more important than RAT)?

The pair wise comparisons were done for all those criteria above. The respondent's judgment, opinion and pair wise comparisons between variables and alternatives of petroleum contracts were collected through the same questionnaires as mentioned in Appendix A.

The results of the questionnaires were processed with Expert Choice 2000 second edition software from Expert Choice, Pittsburgh PA. First for the benefit hierarchy structure, the cost hierarchy and then the risk hierarchy structure followed it. The weightings of benefit, cost and risk criteria were calculated through the comparison of the average score of each combination of the benefit critera, the cost criteria and the risk critera. The rating vector of *Benefits / (Costs x Risks)* was used to weight the corresponding vectors of priorities of the alternatives and to obtain the overall ranking of the alternatives. The highest score of alternative contract system was the most desirable alternative contract system on the petroleum companies' views. Then, as a final step, sensitivity analyses were drawn.

2.4. Investment Climate of the Petroleum Business in Indonesia

World Bank (2004:1 - 2) defines the investment climate as the set of location-specific factors shaping the opportunities and incentives for all companies (from individual farmers and micro entrepreneurs to local manufacturing company and multinationals) to invest productively, create jobs, and expand The companies' decisions to invest will depend largely on the way government policies and behaviours shape the investment climate in those locations. A good investment climate not only generates companies' profits by minimising costs and risks, but also improves the outcome for society as a whole. Improving the investment climate drives the growth of the society and reduces poverty.

Government policies and behaviours make a strong influence in shaping the investment climate through their impact on costs, risks, and barriers to competitions. Therefore government needs to tackle those three criteria in creating a better investment climate. Although the governments have limited influence on geography aspect, they have more significant influence on the security of property rights, approaches to regulation and taxation, the condition of infrastructure, the functioning of finance and labour markets and broader governance features such as corruption and others (World Bank, 2004: 4).

The costs of doing business can be influenced by government policies and behaviours. As example, increasing tax rates might increase the costs of doing business. Governments also have important roles in providing public goods, supporting the provision of infrastructure, and others. Weakness in government performance in these roles can greatly increase the costs of doing business and make many potential opportunities unprofitable. As example, the result of World Bank (2004: 4-5) survey on investment climate of some countries showed that the costs of contract enforcement difficulties, inadequate in infrastructure, crime, corruption and regulation can amount to over 25% of the sale, or more than three times what companies typically pay in taxes. Both the level and composition of these costs vary widely across countries.

Government policies uncertainty, macroeconomics instability, and arbitrary regulation can raise the risks of opportunities and freeze incentives to invest. But governments have important role in reducing the risks by maintain a stable and secure environment, including by protecting property right (World Bank, 2004).

Investment climates vary not only across countries but also within countries because of differences in the way national policies are administered and in the policies and behaviours of sub national governments. Even within single location, the same conditions can affect companies differently depending on the activity they engaged in and their size, often hitting small and informal companies the hardest. Hence creating good investment climates are the responsibilities not only central government, but also local government and business community as well.

Petroleum companies are facing unprecedented pressure to explore and produce new reserves. With demand at an all-time high and increasing pressure to spend profits, companies are looking around the world for opportunities. Investment climate was one aspect analysed in looking at the world for opportunities.

The changes of laws and policies are needed to improve the investment climate, not only on the formal policies improvements, but also more importantly on the implementation of these policies in practice. Over 90% of companies in developing countries report gaps between formal policies and what happens in the implementation (World Bank, 2004: 6).

Indonesia has similar experiences. As example, in improving the investment climate the GOI announced three new laws: the Law No 22 of 1999 that give greater authority to regional governments to manage their internal affair, the Law No 25 of 1999 that addressed sharing or allocation of revenue between the central and regional governments and the Oil and Gas Law No. 22 of 2001 which replaced the 1960 Oil and Gas Law and Law of Pertamina No. 8 of 1971. This Oil and Gas Law eliminates Pertamina's responsibility for administering the upstream petroleum sector to the government agent (BP Migas) and downstream sector to *Badan Pengatur* (BHP Migas). Although the objectives of these laws are very good, but in their implementation there has been uncertainty over details of the implementation of regulations that must be resolved immediately.

From his study about the Indonesian PSC during 1966 to 1999 period focusing on the implementation of management clause, Machmud (2000:183) found some problems occurred in the execution of management clause of the Indonesian PSC such as bureaucracy, tendering rule, the role of BPPKA/Pertamina, the RPTK process on personnel management, crypto taxes, the mark up myth, and others. As opposed to China and Malaysia, Indonesia had *x* factor that created difficulties for investor to calculate cost and profitability. He said that if this *x* factor left unchecked, latter situation would prove extremely damaging to the attractiveness of Indonesian petroleum business.

Machmud (2000:189-190) suggested that there were some issues in Indonesian PSC which needed improvement, including the improvement in Indonesia's investment climate in general and especially for petroleum, addressing seriously all contractors complaints and resolving problems as earliest as possible. PSC contractual provision should be upheld. The involvement of Pertamina should be restricted to approval of work program and budget and should not include involvement in contractor internal affairs, such as personnel matters, expatriate work permits, and control by Pertamina should be through post audit. In addition, a forum should be created for serious periodic discussion, where appropriate, so any controversial issues can be resolved at the earliest time.

In facing the 2001 Oil and Gas Law with the aimed to gain understanding on the senior executives' views on the future of petroleum industry in Indonesia and problems that contributed to the operational constraint, PriceWaterHouseCoopers (2002) conducted a survey to the senior executives of the petroleum companies operating in Indonesia, in which 11 senior executives responded to the survey. Some results (Table 2.13) showed that geological potential of Indonesia had been strong positive aspect supporting investor in to oil and gas activities; with 1.7 score (the most attractive feature). It was followed by the existing PSC framework with 2.6 score, even though they expected that improvements be made on commercial terms of PSC by additional incentives for development of gas resources. Hence Indonesia remained attractive in terms of geological potential and PSC contract framework. In contrast respondents valued the regulatory framework was the least attractive (score 4.5).

The survey also found there were ten most important issues faced by the oil and gas industry. The five most important issues were confusion as to the roles of the central, provincial and regional governments; interference from other government agencies, such as the tax authorities; corruption, collusion and nepotism; community relations; and security of assets, people and ownership rights. They agreed that the major issues urgently in need of improvements were those related to security, legal certainty and contract sanctity. In the absence of legal certainty and contract sanctity investors would have difficulties in evaluating the investment prospect in Indonesia.

In order to understand the implementation of those laws, in the questionnaire PriceWaterHouseCoopers asked the CEOs respondents opinions about the implementation of those laws. The result showed, 70% of respondent agreed that there were confusion between the role of central, provincial and regional government. They also agreed that these issues could be resolved, 25% in year 2003 and another 75% in year 2004 and beyond. When respondents were asked about the opportunity of interference from other governmental agency in their petroleum E&P activities, 80% of respondents agreed that there was interference from the other government agency. As PriceWaterHouseCoopers (2002) survey suggested the urgent need for improved investment climate included ensuring continued acknowledgement of contract sanctity, elimination of operational constraint such as providing security protection of asset, and maintaining legal certainty.

Table 2.13: The rank of parameter for petroleum investment in Indonesia (PriceWaterHouse Coopers, 2002)

Parameter	Score
Geological potential	1.7
The existing PSC Framework	2.6
Trained Workforce	3.4
Foreign Ownership Regulatory	3.5
Contract and Project Approval Process	3.6
Infrastructure	4.1
Regulatory Framework	4.5

Note: 1 = most attractive, 5 = least attractive

Although President Megawati made important strides in maintaining domestic political stability, improving the economy, and routing out domestic terrorists; which encouraged greater confidence in the economy during the first half of 2003, she made much less progress in improving Indonesia's troubled investment climate. Existing and potential investors cite a number of concerns with respect to Indonesia's investment climate, including security, the lack of legal certainty, prolonged contract negotiations, confusion over regional autonomy policies and fiscal decentralization, and tax and labour issues (US Embassy, 2004:1).

Moreover, according to IMF (2004), the Indonesia’s investment climate in 2003 was similar to what mentioned above. The regulatory environment for doing business in Indonesia was considered to be less conducive than in neighbouring countries. Based on the database of the World Bank’s *Doing Business Database* that provided indicators of the cost of doing business by focusing on regulations that enhance or constrain business investment, productivity and growth; starting a business in Indonesia required more procedures and time than in neighbouring countries (as well as to the broader averages in Asia). Legal, institutional, and governance indicators for Indonesia compared unfavourably to neighbouring countries. Measures of the quality of public institutions, government efficiency, and the regulatory environment place Indonesia near the bottom of all countries ranked, and consistently below neighbouring countries. For example, Transparency International's Corruption Perception Index ranks Indonesia 122 out of 133 countries, well below its peers.

IMF (2004) also reported that preliminary results of a joint World Bank-Asian Development Bank private investment climate study, based on responses of 400 companies mainly in Java, suggested that investors were most concerned about macroeconomic instability, policy uncertainty, and corruption. Other important concerns include tax rates and tax administration, cost of financing, the legal system, labour regulations and electricity. Moreover the survey Regional Autonomy Watch identified illegal fees as a major problem of doing business in Indonesia, while a Japanese Bank for International Cooperation (JBIC) study noted that Indonesia had slipped to the sixth largest recipient of Japanese investment in 2003 (from fourth place in 2000), as Vietnam and India took the fourth and fifth places, respectively. The study cited the key factors discouraging investment as the unstable political and social conditions, the local labour difficulties as well as currency and price stability. Is there any improvement in Indonesia's investment climate in 2004?

CHAPTER 3

METHODOLOGY

As noted earlier in Chapter 1 there are four objectives of the study. The methodologies used to reach these four objectives are presented in the following order:

3.1. Methodology to evaluate the commercial performance of the Indonesian PSC during 1966 to 2003 period,
   - 3.1.1. Data collection, data set, population and sampling framework,
   - 3.1.2. Assumption and analysis.

3.2. Methodologies to identify some PSC variables need to be improved as incentives,
   - 3.2.1. Methodology to identify the impact of the application of incentives package 5 and respondent proposed terms on improvement some PSC Variables,
     - 3.2.1.2. Data collection, data set, population and sampling framework,
     - 3.2.1.3. Assumption and analysis.
   - 3.2.2. Methodology to identify the impact of some PSC variables changes and some Petroleum E&P Variables Changes,
     - 3.2.2.1. Data collection, data set, population and sampling framework,
     - 3.2.2.2. Assumption and analysis.
   - 3.2.3. Methodology to identify the impact of tax consolidation application in frontier areas,
     - 3.2.3.1. Single commercial contract analysis,
     - 3.2.3.2. Aggregate combined contracts analysis.

3.3. Methodology to identify the petroleum companies' views with respect to the most desirable petroleum contract system.

3.4. Methodology to identify which aspects of petroleum investment climate needs to be improved.

3.1. Methodology to Evaluate the Commercial Performance of the Indonesian Production Sharing Contracts

Given profitability is the petroleum company's main concern, while on the other hand the government net income is the host government's main concern, thus the revenues from the petroleum E&P business should be sufficient to meet both interests. These two should be balanced. The balance between risks and rewards and the division of benefits between parties of the Indonesian PSC contract was analysed used the principal-agent model theory framework that incorporating incentive structures and risk-reward sharing (sub section 2.1.1 thru 2.1.3). Concerning this model means the reservation utility of the petroleum company that can be replaced by the rate of return of the petroleum company (contractor) expects from a comparable project elsewhere has to be known and, at very least matched. At the same time due the host government want to guarantee can receive maximum revenue from the venture, therefore the host government has to solve the incentive constraint. The utility from working hard (to perform the contract) should be no less than the utility from shirking; it means the profit resulted from the working hard case has to be higher than that resulted from shirking case. For that reason the host government has to pay the petroleum company *x* units above his reservation utility for the contract to be optimal. The valuation of the commercial performances of the application of Indonesian PSC contracts since its first application in 1966 to 2003 period on the parties' views was drawn based on this principle.

The rate of return of the contractor was represented by the contractor's NPV@15%, IRR, contractor take (ratio contractor entitlement to gross revenues) and POT. In this analysis the discount rate to calculate the NPV was set at 15%. While the contractor's IRR was compared with the minimum required rate of return of petroleum investment as suggested by Jones for evaluating petroleum venture as follows:

High risk : 30% - 40%

Medium risk: 20% - 30%

Low risk : 15% - 25%

From the view host government revenue was represented by GOI take (ratio total GOI take to gross revenues).

Evaluation of the representative commercial performance of the application of the Indonesian PSC system requires the same contract's type, time frame of operation as well as the size of operation years, type of production and the same range of production rate of the contracts. Based on their historical operation years, the contracts samples were categorised into three categories, they were 10 years, 20 years and 30 years of operation respectively. Within each operation year they were categorised into contract type, production type and production rate.

In this study, the commercial performances of the Indonesian PSC application were analysed based on the contract type, operation years as well as production type, production rate and by location work area of the contract respectively.

As noted earlier in Chapter 2, since its first application, there had been several generations of Indonesian PSC, from PSC first generation (PSC1, 1966-1975), PSC second generation (PSC2, 1976 – July 1988), to PSC third generation (August 1988 – recent). Additionally, there were 5 incentive packages inside PSC3, which included the Incentive Package 1 (IP1, August 1988 – February 1989), Incentive Package 2 (IP2, March 1989 – July 1992), Incentive Package 3 (IP3, August 1992 – December 1993), Incentive Package 4 (IP4, 1994 - 2002), and the newest, Incentive Package 5 (IP5, 2003 - recent). Each generation had its time frame around 10 years, except the PSC third generation with its five incentive packages, which had more than 15 years time frame. It was difficult to search the detail contents of all 257 PSC contracts; therefore in this analysis it was assumed that the contracts could be categorised based on the time frame they were signed. For example PSC contracts signed between 1966 and 1975 period was of PSC1 type;

contracts signed between 1976 and July 1988 period belonged to PSC2 type and so on.

Based on the type of hydrocarbon produced, the PSC contracts could be categorised as oil producing only, gas producing only or oil and gas producing contracts. While based on production rate, the PSC contracts could be categorised into five field sizes. They were:

(a) Small Field: field with production rate less than 10 thousand barrels oil per day (MBOPD) for oil or less than 10 thousand oil equivalent per day (MBOEPD) for oil and gas.
(b) Medium Field: field with production rate between 10 – 50 MBOPD/MBOEPD.
(c) Large Field: field with production rate between 50 – 100 MBOPD/MBOEPD.
(d) Very Large Field: field with production rate over 100 MBOPD/MBOEPD.
(e) Extra Large Field: field with production rate over 200 MBOPD/MBOEPD.

Geographically, the contracts can be classified based on the work area of petroleum E&P operation, namely western-part and eastern-part of Indonesia. Sumatra, Natuna, Java, Kalimantan islands and their surrounding ocean are classified as western-part of Indonesia, while starting from the east of 200 m offshore Kalimantan in Makasar Strait to Bali, Lombok, Maluku and Irian Jaya islands and their surrounding ocean are classified as eastern-part of Indonesia work area. In addition, the contracts can also be classified based on onshore and offshore locations of the contracts. Petroleum E&P activities in the land or island is called onshore work operation while the petroleum E&P activities in water such as river and ocean are called offshore work operation.

3.1.1. Data Collection, Data set, Population and Sampling Framework

The data collection was performed by primary data and secondary data. The primary data were collected from historical financial & non-financial data of petroleum contractors that were active in Indonesia during 1966 – 2003 periods from unpublished BP Migas and Pertamina databases while the secondary data were collected from various publications including official and unofficial reports from BP Migas, Pertamina, US Embassy Jakarta Petroleum Report and others, books, journal, as well as research papers and articles, which were published, unpublished or presented in various seminars and others.

Since its first application in 1966 to 2003, there were 257 PSC contracts signed in Indonesia (see Table 3.1). Out of these, only 32 PSC contracts (12% of total 257 PSC contracts) produced commercially, 73 contracts were still in exploration phase and the remaining 152 contracts were already terminated.

Table 3.1: PSC contracts signed during 1966 – 2003 based on contract type

No	Time Frame / Contract type	Total Indonesia			
		Producing	NonProd.active	Terminate	Total
1	PSC1	18		41	59
2	PSC2	8(1)*	3	53	64(1)*
3	PSC3+IP1		1	5	6
4	PSC3+IP2	3	5	25	33
5	PSC3+IP3	3(2)*	4	2	9(2)*
6	PSC3+IP4		44	26	70
7	PSC3+IP5		16		16
	Total	32(3)*	73	152	257(3)*

*Note: * (..) number in bracket was the number of extended contract*

Out of these 32 producing contracts, three contracts were the extension of the COW system; they were extended to one PSC2 contract and two PSC3+IP3 contracts (see Table 3.2). As a result only 29 new producing PSC contracts (11% of total contract) are active recently. Moreover, five producing contracts did not have complete and accurate financial data; hence, they could not be used as samples. Thus only 24 contracts were used as the data set to identify the commercial performances of the producing PSC contracts.

Table 3.2: Producing PSC contracts during 1966 – 2003 based on contract type

	PSC1	PSC2	PSC3+IP2	PSC3+IP3	Total
Total Producing PSC contracts	18	8	3	3	32
Extension of COW		1		2	3
Population	18	7	3	1	29
Data do not complete	3		2		5
Can be used as samples	15	7	1	1	24

Samples were taken from those 24 contracts. Entire data set that had 30 years, 20 years and 10 operation years were analysed and categorised by contract type, operation years, production type and production rate, as explained previously. Additionally, especially to evaluate the commercial performance of each work area as one field, entire historical data of PSC contracts, including producing, non-producing and terminated contracts, in each area during 1966 – 2003 period were combined as one field, as representative of each work area.

3.1.2. Assumption and Analysis

The financial model of the PSC contracts followed the Indonesian PSC financial model as shown in Chapter 2 section 2.2.3. The independent variables were the expenditures, production, prices profiles of the field; the dependent variables were the NPV, IRR, as well as contractor take, POT and GOI take respectively. While the PSC variables, i.e. the first tranche petroleum (FTP), investment credit, contractor production sharing split, DMO holiday price and tax rate were the changes variables. Cash flow analysis was used to evaluate the commercial performances of the producing PSC contracts on the views of both parties, the PSC contractor and the GOI, and was analysed based on the contract type; operation years as well as production type and production rate of the PSC contract respectively.

Some basic assumptions taken in the empirical cash flow analyses were:

(a) Historical financial and non-financial data of the producing PSC contracts were used in the analyses.
(b) To categorise the contract type based on the time frame when it was signed.
(c) Each contract was treated as one field petroleum E&P operation.
(d) In the case that the size of samples within a category was more than one, an average result is taken as the representative of this category.

Especially to evaluate the commercial attractiveness of each work area, two cash flow analyses were done for each work area, which is western-part, eastern-part, onshore and offshore of Indonesia. The objective of the first analysis was to identify the commercial attractiveness of contracts in each location area. Assumption taken was similar with basic assumption mentioned above. The commercial attractiveness of each location was taken from the mean of the result of analysis of samples on each location. The objective of the second analysis was to evaluate the commercial attractiveness of each location as one field. In addition to the basic assumptions above, other assumptions taken in this analysis were:

(a) Each location was treated as one field petroleum operation.

(b) Data were taken from historical financial and non financial data of entire PSC petroleum companies operated on each location included producing PSC contracts, non-producing actives and terminated PSC contracts during 1966 – 2003 and combined as one field operation.

The results were analysed based on the contractor's NPV@15%, IRR, contractor take (ratio of contractor entitlement to gross revenues) and POT for the contractors' point of view; and GOI take (ratio total GOI to gross revenues) for the GOI view. While the contractor's IRR was compared with the minimum required rate of return of petroleum investment as suggested by Jones that already mentioned above.

3.2. Methodologies to Identify Some PSC Variables need to be Improved as Incentives

To identify some PSC variables need to be improved as incentives in raising the attractiveness of the Indonesian PSC system and in turn hopefully could increase the petroleum E&P investment level in Indonesia also used the principal-agent model theory framework that incorporating incentive structures and risk-reward sharing as noted in section 3.1. Under the premise that higher risk should be balanced with higher reward, the host government must be aware and accept that in the higher risks investment situation the government income can be lower. Higher risk investment needs more incentives to raise the reward, and incentives given should be based on reasonable economic and given on the whole life cycle of the venture. The host government must consider these principles in decision-making policy in organising the petroleum contractual arrangement.

The PSC variables to be analysed were the first tranche petroleum, the investment credit, as well as depreciation method in recovering the capital expenditures, the contractor production sharing split, the domestic market obligation price, the DMO holiday price and the tax rate respectively.

As already noted, first tranche petroleum (FTP) is a portion of petroleum production taken firstly before any deduction of cost recovery and will be shared between GOI and contractor per year based on production sharing split as specified in the contract. The objective of the FTP is to guarantee the GOI income at production commencement. Before IP5 introduction in 2003, the FTP was set up at 15% and shared between contractor and GOI with production sharing split as stated in the contract. Under the IP5, the FTP is decreased to 10 % but all are for the GOI benefit. In this case the FTP is similar to royalty payment. Decreasing FTP size is one of possible incentives since it will shorten time to recover the contractor expenditures.

Investment credit allows the contractor to recover an additional percentage of capital costs through cost recovery. The credit is taken out of gross production before recovering the expenditures. It is subject to taxation and may be carried forward to succeeding years if it is not fully taken. Under the IP5 the investment credit is set up at 15.78% for conventional field and 102.14% for marginal field and frontier area/deep areas. Increasing the investment credit size is one of possible incentive in order to attract investor.

The Indonesian PSC system allows capital expenditures to be recovered through five years double declining balance (DBBL) method. Loosening the depreciation method will shorten the time recover the capital expenditures.

Production sharing split is the main term in PSC. Profit oil or profit gas is gross revenue less the FTP less cost recovery less investment credit. This profit is shared between the contractor and the GOI using the production split as specified in the contract. The profit is also subjected to taxation. In PSC1, for conventional area, the contractor's production sharing split (cpss) was set at 15%; the remaining 85% was for GOI. Under IP5, the cpss varies based on the geological condition, ranging from 20% to 35% for oil and from 35% to 40% for gas. Higher cpss logically will make higher profit for contractor, but consequently it will lower the GOI income.

Government specifies a percentage of the contractor's profit oil should be sold to the government at discounted price, called Domestic Market Obligation (DMO). The quantity of the DMO varies from contract to contract, provided that the pro rata quantity does not exceed 25% of contractor production share from its contract area. The goal of DMO is to give security for the oil and gas domestic supplies for the host country. The DMO price in the IP5 term was set up at 15% of export price for conventional field and 25% of export price for small (marginal) field. Increasing the DMO price is one possible incentive can be given. For the first five years oil production (new oil), the price of oil for DMO is set up as export price, it called DMO holiday price. The longer DMO holiday period gave will make higher income for contractor during its earlier of production; hence it can be one of possible incentive to attract investor.

In 1995 the income tax rate were reduced to 30% of taxable income and 20% of dividend tax, which together make a total 44% of tax income rate. Decreasing the tax rate is one possible incentive can be given to attract investor. The methodologies are presented in the following sub sections.

3.2.1. Methodology to Identify the Impact of Application of the Fifth Incentives Package and Respondents' Proposed Terms on Improvement some PSC Variables

3.2.1.1. Data collection, Data set, Population and Sampling Framework

Data collection and data set were similar as noted in section 3.1.1. The primary and secondary data collected were also from similar sources as noted in that section. In addition to data above, the other primary data of the CEOs petroleum companies' proposed terms on improving some PSC variables were collected through questionnaires.

A survey through questionnaires involving CEOs of petroleum companies operating in Indonesia and petroleum experts was conducted. Three objectives of the questionnaires (see Appendix A) were as follows:

(1) To collect the CEOs' suggestions to improve some PSC variables.
(2) To collect their judgment, opinion and pair wise comparisons of some benefits, costs and risks variables of the petroleum E&P business in Indonesia.
(3) To collect their views about some investment climate variables of petroleum business in Indonesia.

The results of item number (1) were used to identify the impact of the application of the CEOs' proposed terms on the contractor's profitability and GOI income and were compared with the results of the historical case and the application of the IP5 terms. The results of item number (2) were used on the benefit-cost-risk analysis with AHP presented in section 3.3 below. The results of item number (3) were used to identify some variables of Indonesia's investment climate discussed in section 3.4 below.

Before distributing the questionnaire, we had sent the questionnaire's draft to four petroleum experts, to get their comments in improving it. Two of them responded and gave comments in improving the questionnaire. The improved questionnaire was distributed to the respondents.

Two groups of respondents were chosen:

(a) The Chief Executive Officers (CEOs) of the petroleum companies, which were currently active in Indonesia. The samples were taken from the population of the petroleum companies currently active in Indonesia.
(b) The petroleum experts, who did not represent either the petroleum companies or the GOI, but had expertise and experiences in managing E&P venture in Indonesia.

The criteria of the respondents were: persons who were involved and or held authority (recent or former) in decision making in petroleum E&P investment of the company; had experiences and or educational background in the field of engineering, petroleum economics, business, management, law or others that were relevant with decision making in petroleum E&P investment.

Data from BP Migas (BP Migas, 2004) showed that in 2004 there were 121 active petroleum contracts and managed by BP Migas, consisted of 101 Production Sharing Contract (PSC); 18 Joint Operation Agreement (JOA) and Joint Operation Body (JOB); and two Technical Assistance Contracts. Out of the total, 37 contracts were producing and 84 contracts were in the development or exploration phase. The producing contracts included 29 PSC, six JOA and JOB, and two TAC.

The Indonesian regulation stated that each of petroleum contract must be administered by one company, hence one petroleum company may have more than one contracts, thus in terms of operating petroleum companies the actual number would be less than 121 companies. On the contrary several companies may own a contract. Due the high dynamic activities of petroleum companies, the changes of the participants of the petroleum company's share, the operator and the contractor move rapidly, the owners could change rapidly through merger, acquisition, takeovers or others. As example during 1999 - 2002 period there were about 4 acquisitions, 14 mergers and 9 takeovers of petroleum companies happened in Indonesia (US Embassy, 2004:15-16). Moreover the participant of a petroleum company shareholder can be more than one, as examples around 50% out of total producing PSC contracts in the data set was owned by more than three companies. Consequently it was difficult to search the exact number of petroleum companies currently active in Indonesia. From the PSC contracts data, we found around 24 petroleum companies. The questionnaires were sent to these 24 petroleum companies and five petroleum experts (retired petroleum executives) as respondents during March to August 2004.

The population of the analysis were the producing PSC contracts that already had 30 operation years. In facts only 12 PSC1 contracts type already had over 30 operation years. Stratified random sampling method by production type and production rate was taken from those 12 producing PSC1 during their 30 operation years, which each category of production rate and production type was represented by one sample.

3.2.1.2. Assumption and Analysis

The simulations of cash flow analyses were done for samples as the representative of each category. The financial model of the PSC contracts followed the Indonesian PSC financial model as shown in Chapter 2 section 2.2.3. The independent variables were the expenditures, production, prices profile of the field; the dependent variables were the NPV, IRR, as well as contractor take, POT and GOI take respectively. While the PSC variables, i.e. the first tranche petroleum (FTP), investment credit, contractor production sharing split, DMO holiday price and tax rate were the changes variables. Except the PSC variables figures proposed by the CEO's petroleum companies through questionnaires, the detail of scenarios and assumptions of the simulations taken can be seen in Table 3.3.

Expenditures, productions and prices profile were taken from contractor's historical data and were treated as the base case. As the expenditures data were supplied as a total for each contract, the simulation assumed that the capital expenditures was set at average capital to total expenditures during 1994 to 2003 period ratio multiplied by the total expenditures. Investment credit in all scenarios was taken from the investment credit for oil production, while the interest recovery and GOI participation were assumed not available.

Five simulation cash flow scenarios analyses were run; one case utilised the historical PSC1 contract terms (actual case), referred to as the base case (see detail figures of IP5 terms of each PSC variables in Table 3.3); one case used incentive package 5 financial terms for conventional field (IP5-conv case, the lowest figures); one case utilised the incentive package 5 for the marginal field (IP5-mar case, the highest figures); while two cases used the respondent's proposed terms, one with and the other without depreciation method. The latter included one case which assumed the five years double declining balance for recovering the capital cost (quest+depre case) and one case which assumed that the capital cost were treated similar to the non-capital cost, it was recoverable at the year when it spent or without depreciation (quest-nodepre case). In these two latter cases (quest cases) the PSC financial variables were taken from the result of the questionnaires. The contractors' NPV@15%, IRR, contractor take (contractor entitlement in % of total revenues) and POT for the contractors' point of view and GOI take (total GOI take in % of total revenues) for the GOI's view of the five cases were analysed used the principal-agent model theory framework that incorporating incentive structures and risk-reward sharing as shown in Chapter 2 subsection 2.1.1 thru 2.1.3 and Chapter 3 sub section 3.1.

Table 3.3: Scenarios and Assumptions

Base case	:	Expenditures, productions, prices from one life cycle contractors historical data
Operation years	:	One life cycle of PSC (30 years)
Production	:	Oil only or oil & gas
Capital Expend.	:	Average Indonesia's capital exp. to total exp. ratio during 1994 – 2003 period times total expenditures = 22.3% x total expenditures
Investment Credit	:	Investment credit was taken from investment credit of oil
Interest Recovery	:	Not available
GOI participation	:	No participation

No	Variables	Historical (PSC1)	PSC3 + IP5 Terms	
			Conventional field	Small (Marginal) field
1	FTP	Historical data	10% all for GOI	10% all for GOI
2	Depreciation	5 years DDBL	5 years DDBL	5 years DDBL
3	Investment Credit	No	15.7800%	102.1400%
4	DMO			
	- DMO quantity	25% of contr. prod share	25% of contr. prod share	25% of contr. prod share
	- DMO holiday price	5 years	5 years	5 years
	- DMO Price	20ct USD/B	15% of export price	25% of export price
5	Oil Split: GOI : Con			
	- After-tax	85 : 15	80 : 20	65 : 35
	- Before-tax		64.2857% : 35.7143%	37.5000% : 62.5000%
6	Gas Split: GOI : Con.			
	- After-tax	65 : 35	65: 35	60 : 40
	- Before-tax		37.5000% : 62.5000%	28.5714% : 71.4286%
7	Tax	56% and 48%	44%	44%

3.2.2. Methodology to Identify the Impact of some PSC Variables and some Petroleum E&P Variables Changes

3.2.2.1. Data Collection, Data set, Population and Sampling Framework

Data collection and data set were similar as noted in sub section 3.1.1. The primary and secondary data collected were also from similar sources as noted in that section with the exception of the CEOs' proposed terms. The sampling method of the analyses was similar with the sampling method presented in sub section 3.2.1.1.

3.2.2.2. Assumption and Analysis

The simulations of cash flow analyses were done for samples representative of each category. The financial model of the PSC contracts also followed Indonesian PSC financial model as shown in Chapter 2 section 2.2.3. The independent variables also were the expenditures, production, and prices profiles of the field; while the dependent variables were the NPV, IRR as well as contractors take, POT and GOI take respectively. The PSC variables taken as the changes variables for analyses were the first trance petroleum, the investment credit, the depreciation method in recovering the capital expenditures, the contractor production sharing split, the domestic market obligation price, DMO holiday price and tax rate. The scenarios and assumptions of the cash flow simulation taken were also similar the ones shown in Table 3.3. The application of IP5 terms was used as the base case.

In order to identify the impact of the improvement of FTP, for each sample case (small oil field, medium oil field, large oil field, medium oil & gas field, large oil & gas field, very large oil & gas field, extra large oil & gas field), eight cases cash flow analyses were drawn, which can be divided into two groups. The first group assumed that the FTP 100% for the GOI's benefit, while the second group of scenarios assumed that the FTP shared between contractor and GOI. For both groups, the FTP was varied of 12.5%, 10% and 7.5% (these were the 10% FTP of IP5 term increased and reduced by 25%), while the other variables were kept constant. In the second group the variation of FTP were added with 15% and 20%.

While in order to identify the impact of the improvement of investment credit, depreciation method, production sharing split, DMO price, DMO holiday price, and tax rate on the profitability of contractor and GOI income; two models scenarios cash flow simulations analysis were drawn of each sample case (small oil field, medium oil field, large oil field, medium oil & gas field, large oil & gas field, very large oil & gas field, extra large oil & gas field). First, the base case cash flow model, in which the IP5 terms were applied (the detail figures of IP5 terms of each PSC variables can be seen in Table 3.3). In the second model, while the other variables were kept constant, for each sample case simulation were drawn for six PSC variables changes as follows:

- The investment credit increased 25% of its IP5 term figures (inv.crdt.up case). In small (marginal) field case from 102.140% as the base case increased to 127.675%, and in conventional fields (medium, large and over fields) from 15.78% increased to 19.725%.
- Recovering the capital expenditures without depreciation (nodepre case).
- The contractor production sharing split increased 25% of its IP5 figures (cpss.up case), in small (marginal) field case from 35% as the base case to 44% for cpss oil and from 40% to 50% for cpss gas, while in conventional fields (medium, large and over fields) from 20% to 25% for cpss oil and from 35% to 44% for cpss gas.
- The DMO price increased 25% of its IP5 figures (DMOpr.up case), in small (marginal) field case from 25% of export price as the base case to 31.3% of export price and in conventional fields (medium, large and over fields) from 15% of export price to 18.75% of export price.
- The DMO price holiday increased 25% of its IP5 figures (DMOhol.up case), from five years as the base case to 6 years.
- The tax rate decreased 25% below its IP5 figures (tax down case), from 44% as the base case to 33% tax rate.
- The oil and gas prices increased 25% of their historical figures.
- The expenditures increased 25% of their historical figures

- The production profile increased 25% of their historical figures.

The contractors' NPV@15%, IRR, contractor take (contractor entitlement in % of total revenues) and POT for the contractors' point of view and GOI take (total GOI take in % of total revenues) for the GOI's view were analysed used the principal-agent model theory framework that incorporating incentive structures and risk-reward sharing as shown in Chapter 2 subsection 2.1.1 thru 2.1.3 and Chapter 3 sub section 3.1.

To determine the most and the least sensitive parameters, the projected results were presented in Tornado diagram (see Figure 3.1). In each simulation case, the results were compared with the base case in percentage changes in Tornado Diagram. Tornado Diagram or chart is a device used with stochastic models that illustrates the degree to which a function (the output) is influenced by each of its parameters. The uncertainty in the variable associated with the largest bar, the one at the top of the chart, has the maximum impact on the result, with each successive lower bar having a lesser impact. As example, Table 3.4 and Figure 3.1 show the impact of the changes of contractor production sharing split (cpss) 25% up from the base-case. The impact of changing variable was compared to the base case in percentage. In the case of GOI Take declined from the base-case 60% to 58% as a result of 25% cpss increased then the result from increasing 25% of cpss was 96% of the base-case. If GOI Take of base-case was assumed = 0, then GOI Take decreased to minus 4% below the base case as result of cpss increased and so on. Figure 3.1 also shows the highest impact of the cpss changes was on the changes of NPV@15% (31%) that had the longest bar placed in the top of the chart. The NPV@15% was the most sensitive variables to the changes of cpss. It was followed by IRR, contractor take, GOI take and POT was the least.

Table 3.4: Calculation method of the result of the cash flow analysis

Result	**Base case**	**The actual result if cpss up 25% of base case**	**The result if cpss up 25% compared to base case (base case = 100%)**	**Assumed base case = 0**
POT	7	7	0%	0%
GOI Take	60%	58%	96%	-4%
Contractor Take	40%	42%	107%	7%
IRR	36%	40%	111%	11%
NPV@15%/B	0.17	0.23	131%	31%

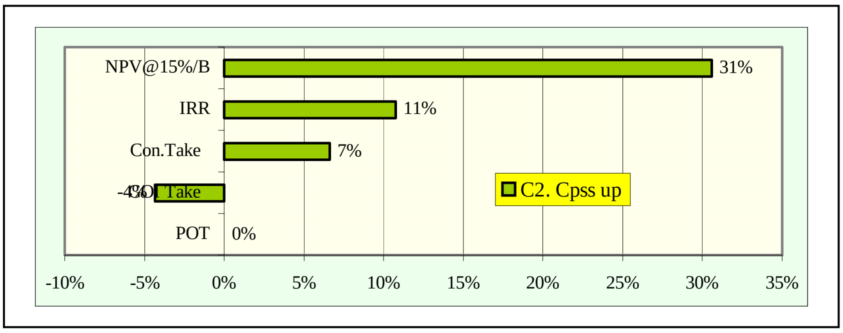


Figure 3.1: Example of Tornado Diagram of contractor production sharing split changes

3.2.3. Methodology to Identify the Impact of Tax Consolidation Application in Frontier Areas

The Monte Carlo simulations were drawn to identify the impact of the tax consolidation application in frontier areas not only on the income of GOI and contractor's profitability but also to quantify the risk involved and compared with the impact of increasing the contractor's production sharing split. The tax consolidation application was set up strict to improve the exploration activities in frontier area only.

Two simulations were drawn, as follows:

a) Single commercial contract analysis,
b) Aggregate combined contracts analysis.

3.2.3.1. Single Commercial Contract Analysis

To compare how tax consolidation application in frontier area affected the GOI's income and contractor's profitability in case of commercial discovery, single commercial contract was considered. Six possible scenarios combined of tax consolidation and increasing contractor's production sharing split were investigated:

(a) 65/35 production sharing split without tax consolidation (fifth incentives package figures) as the base case,
(b) 65/35 production sharing split with tax consolidation,
(c) 60/40 production sharing split without tax consolidation,
(d) 60/40 production sharing split with tax consolidation,
(e) 55/45 production sharing split without tax consolidation,
(f) 55/45 production sharing split with tax consolidation.

The financial model of the PSC contracts followed the Indonesian PSC financial model as shown in Chapter 2 section 2.2.3. Other than the contractor production sharing split and the tax consolidation above, the assumptions of the other PSC variables were set up at the highest figures of the fifth incentives package variables as summarised in Table 3.5. They were as follows: the signature bonus was 26.6 million USD; the FTP of 10% in sense all go to GOI; the production sharing split of 65/35 in favour of GOI; the investment credit of 102.14%; the depreciation of five years double declining balance; the DMO price of 25% of export price; the DMO holiday price of five years and the tax rate of 44%.

The first assumption was the tax consolidations were applicable strictly to cover exploration cost in frontier areas only. Duration of each activity was set up at one life cycle of PSC contract, 30 years. The exploration phase of each contract was assumed to be performed in the first 3 years, followed by development phase, if there was commercial discovery, which covers year 4 to year 8. Analysis was limited to the additional contracts signed in the first 10 years after tax consolidation was issued.

The input variables were the total additional contract in frontier area/year, the exploration cost, the tax rate, the successful discovery, the commercial discovery, the reserve discovery size, the development cost (capital and non capital costs), the production cost, the production type, the production profile and the oil prices.

Table 3.5: Assumptions in Tax-consolidation simulation

MODEL The Indonesian PSC financial model as shown in Chapter 2 section 2.2.3			
PSC CONTRACT TYPE The Fifth Incentives Package (the highest figures)			
1	Signature bonus	26.6 million USD	
2	Minimum Exploration commitment	140.9 million USD during the first three operation years	
3	FTP	10% all for GOI	
4	Depreciation	5 years DDBL	
5	Investment Credit	102.14%	
6	Contractor production sharing split	35%	
7	- DMO quantity	25% of contractor production share	
8	- DMO holiday price	5 years	
9	- DMO Price	25% of export price	
10	Tax rate	44%	
SCENARIO AND ASSUMPTION			
No	**Items**	**Assumption**	**Remark**
11	Tax consolidation application	Strictly to cover exploration cost in frontier areas only	
12	Analysis was limited to	The additional contracts signed in the first 10 years after tax consolidation was issued	Historical showed that each PSC generation effectively used around 10 years after that changed to other generation
13	Duration of contract	30 years	Duration PSC contract life cycle
14	Period of analysis	2004 –2033 period	
15	Discount rate and discount date	25% 1/1/2004	
INPUT VARIABLES ASSUMPTIONS			
16	Exploration cost/area	Uniform probability distribution with minimum and maximum value of 140.9 and maximum of 200 million USD. All values were at 2004 value.	The minimum value was set up at the minimum exploration commitment as stated in the IP5 terms (140.9 million USD for the first three years contract), while the maximum value was set up at roughly three times the historical maximum exploration expenditures cash out in 2003 (BP Migas, 2004).
17	Development expenditures/barrel	Uniform probability distribution between 6 to 9 USD/barrel, in which 50% was capital expenditures.	The minimum value was set up at the 2004's average of development cost of 24 US petroleum companies that operated in other eastern hemisphere (except Midle East), while the maximum value was set up at the 2004's average of development cost of world operation of 24 US petroleum companies (EIA, 2006:34). If there was commercial discovery that covers year 4 to year 8
18	Escalation of cost rate	3% / year	Average of the changes of US Consumer Price Index during 1990 – 2003 period
19	Fixed production cost	Uniform probability distribution with minimum and maximum values of 20 and 30 million USD	Educated guess. The combination of fixed and variable operating cost give mean of total operating cost of 4.31 USD/barrel in line with 2004 EIA data (EIA, 2006:34).
20	Variable production cost	Uniform probability distribution between 1.0 to 1.5 USD/barrel	See above
21	Year production start	Year 6	
22	Hydrocarbon produced	Oil	
23	Production profile trend	Constant plateau rate for first three years of production then decline exponentially	Plateau rate set to 11% of reserve. Initial decline rate 17.4 %/year
24	Oil price	Triangular distribution with minimum, mode and maximum values of 9, 21 and 76 USD /barrel respectively, in 2004 value	Approximation of historical US crude oil price during 1974 – 2003 period, adjusted to 2004 value.
25	Oil Price escalation	3%/year	Average changes of historical US crude oil price during 1974 – 2003 period
OUTPUT VARIABLES			
26	**GOI view:** GOI's NPV@25%, IRR and reserves addition value and probability distribution		
27	**Contractor view:** Contractor's NPV@25% and IRR value and probability distribution		

The total probability distribution of additional contract in frontier area / year was assumed to be triangular probability distribution with minimum, most likely and maximum values of each scenario would be discussed latter below in the methodology of aggregate combined contracts. The probability distribution of exploration expenditures for each area was assumed to be uniform distribution with minimum and maximum values of 140.9 million USD and 200 million USD respectively. The minimum value was set up at the minimum exploration commitment as stated in the IP5 terms (140.9 million USD), while the maximum value was set up at roughly three times the historical maximum exploration expenditures cash out in 2003 (BP Migas, 2004). All values were at 2004 value.

The tax rate was assumed similar to the IP5 terms of 44%. In the scenarios with tax consolidation, the tax consolidation cost to government was assumed as tax rate times the total exploration cost. In contrast there was no cost in the scenario without tax consolidation, the GOI income was the total GOI take in the entire scenarios. Therefore in the scenarios with tax consolidation, the tax consolidation cost to GOI was 44% of the total exploration expenditures while the remaining 56% of total exploration expenditures was the cost for contractors. The exploration expenditures were distributed evenly from the first to third years of the contract. It was assumed in single commercial contract analysis that the minimum commercial reserve size was 150 millions barrels of oil (Conoco Phillip, 2004).

The development cost per barrel, if there was commercial discovery, was assumed to have uniform probability distribution with minimum and maximum values of 6 and 9 USD per barrel respectively. The minimum value was set up at the 2004’s average of development cost of 24 US petroleum companies that operated in eastern hemisphere (not including Middle East area), while the maximum value was set up at the 2004’s average of development cost of world operation of 24 US petroleum companies (EIA, 2006:34). Half of the development cost was assumed to be capital expenditures. In the case of commercial discovery, the development cost was distributed evenly from year 4 to year 8 and escalated by 3% per year. This value was an average of the annual changes of US Consumer Price Index during 1990 to 2003.

The production cost was divided into two types, fixed production cost and variable production cost. Fixed production cost represented the expenses that were independent of production rate, while variable production cost represented the expenses that were dependent on the production of the field. The fixed production cost was assumed to have uniform distribution with minimum and maximum values of USD 20 and 30 millions respectively, while the variable cost was assumed to have uniform distribution with minimum and maximum values of 1 and 1.5 USD/barrels respectively. The production cost was also escalated by factor of 3% per year. While the probability distribution values of the production costs, both fixed and variable were based on educated guess, these values gave mean total production cost of around 4.31 USD/barrel. For comparison purpose, the 2006 EIA data showed that the average lifting cost worldwide was 4.25 USD/barrel, while for eastern hemisphere (not including Middle East area), the cost was 4.26 USD/barrel (EIA, 2006:34).

The type of hydrocarbon produced in each discovery was assumed to be oil. The production starts in year six, where the oil yearly production was linearly increased from 50% of the plateau production to 100% plateau production in year 9. The yearly plateau production was set at 11% of the reserve. The plateau production was maintained for 2 years, afterward the production declined by 17.4% exponentially each year. Figure 3.2 shows the production profile in term of percentage of the total reserve.

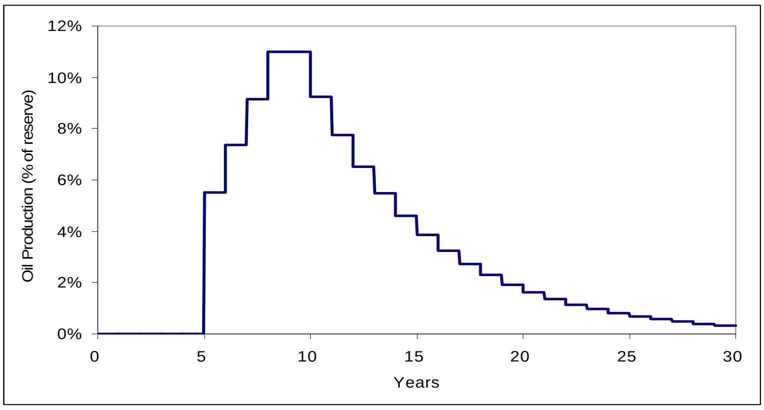


Figure 3.2: Yearly oil production profile for commercial contracts

Oil price probability was assumed to have triangular probability distribution with most likely of 21 USD per barrel. The minimum and maximum prices were set of 9 to 76 USD per barrel respectively. This distribution was based on the approximation of actual yearly historical US crude oil price distribution since 1974 (after the historical OPEC embargo) adjusted to 2004 USD value. The oil price was escalated by 3% per year; this value was an average annual change of historical US crude oil price from 1974 to2003.

To properly characterize the possible outcomes, the Monte Carlo simulations were drawn 10,000 times using Crystal Ball software academic professional edition version 7.2 from Decisioneering Inc.

The output variables from the contractor’s view were the size and the probability distribution of contractor’s NPV@25%, as well as the IRR. While from the GOI’s view, the output variables were the size and the probability distribution of GOI’s NPV@25%, IRR as well as the reserve addition. It was assumed that the tax reduction in tax consolidation scenarios was the GOI cash outflow or investment, so that the GOI’s IRR can be calculated. The analyses of the output variables also used the principal-agent theory framework as noted in section 3.1.

To simplify the comparison between tax consolidation application and production split increased, three scenarios were analysed in more detail as follows:

a) The 65/35 production split case without tax consolidation, which were referred as the base case,
b) The 65/35 split case with tax consolidation, which were referred as the tax consolidation case, and
c) The case with 55/45 production split case without tax consolidation, which were referred as the production split increase case.

In effect, the comparison was between the most conservative tax consolidation scenario and the most progressive production split scenario. Another comparison also made as well in term of the ratio of contractor’s Cash Flow and contractor’s share of exploration cost:

$$(NCF\ /\ EC\ )Ratio\ =\frac{NetCashFlo\ \ w_{contractor}}{Exploratio\ \ n\,Cost\ _{contractor}}$$

The ratio of contractor's Net Cash Flow to its Exploration cost will be used to calculate the approximate probability distribution of the number of contracts signed each year in aggregate combined contracts analysis below.

3.2.3.2. Aggregate Combined Contracts Analysis

To analyse whether the increase in exploration activity associated with tax consolidation were beneficial to the GOI or not, another Monte Carlo simulation was evaluated. This time, the analysis was not based on single commercial contract; rather, the analysis was performed on the combined contracts basis. The simulation was done for two scenarios; tax consolidation with 65/35 contractor production sharing split, and production sharing split 55/45 without tax consolidation, i.e. the conservative tax consolidation and progressive increasing production split scenarios.

The assumptions used in addition to the ones explained above were as below. The analysis were limited to only the additional areas signed during the first 10 years since tax consolidation or increase in production split (55/45) started to be effective. While the number of contracts signed each year under tax consolidation scenario was assumed to have triangular probability distribution with,

a) Tax consolidation case (production sharing split 65/35 with tax consolidation): most likely value of 3, minimum and maximum values of 0 and 6 respectively.
b) Progressive improved production split case (production sharing split 55/45 without tax consolidation): most likely, minimum and maximum values were set up at ratio of NCF/CE of production split 55/45 case to NCF/CE of tax consolidation case times its each value in tax consolidation case.

The success probability of commercial discovery of each contract was assumed to be normally distribution, with mean 12.5% and P5 of 14.51; this value was set up at historical average ratio of producing PSC contract to total PSC contract signed during 1966 – 2003 in Indonesia. Assuming that the minimum commercial reserve discovery in frontier area was 150 million barrels (ConocoPhillips, 2004); the probability reserves size was assumed to have Pareto distribution with location 150 million barrels and P5 of 450 million barrels.

The total exploration cost described previously was applied only to contracts that discover oil reserve (whether commercial or non-commercial). If there were no discovery made, the exploration cost would only amounted up to 2/3rd of the total exploration cost of contract with discovery, distributed up to the first two years of the contract. The above assumption was made in consideration that if any discovery were made after the drilling of the first few wells there would be more exploration activity to delineate and determine the reserve size and its commerciality. While if there were no discovery after the first few wells, then exploration activity was stopped.

The outcomes considered in this Monte Carlo simulation would the aggregate GOI and contractor's NPV@25% and IRR as well as the reserve addition. It means that the cash flows of all possible contracts were combined into single cash flow to determine the aggregate NPV@25% and IRR. Similar to the single contract simulation, assuming that the tax reduction was the GOI cash outflow/investment, so that the GOI's IRR can be calculated. The output variables were be analysed used the principal-agent theory framework as noted in section 3.1.

3.3. Methodology to Identify the Petroleum Companies' Views with Respect to the Most Desirable Petroleum Contract System

As already mentioned earlier petroleum companies experiences, expertise, information and knowledge in doing petroleum E&P business as well as changes the business environment and investment climate in Indonesia could change their perception and judgments about the petroleum business in Indonesia, these will also determine their judgment about the benefit, the cost and the risk of the petroleum E&P operation in Indonesia. Thus petroleum companies experiences and the

Indonesia’s geological potential, economic, social and political conditions changes can transform the contractor’s view, which is the most desirable petroleum contract system that suitable given those conditions.

In order to attract investor, one alternative that can be used by GOI is offering the investor’s desirable contract system. Consequently GOI needs to identify the petroleum company’s view with respect to the most desirable petroleum contract system.

Analytical Hierarchy Process (AHP) in the benefit cost and risk framework was drawn to identify the petroleum companies’ views with respect to the most desirable contract system, given recent geological potential, diminishing exploration activity, economic, social, security, political condition of Indonesia. The analysis was drawn based on the theoretical and methodology framework of AHP and model as described in Chapter 2 sub section 2.3.2. The first step of the analysis was to set up the goal of the AHP analysis. The Goal is to identify the most desirable petroleum contract system in the views of petroleum companies that attracts petroleum companies to invest in upstream petroleum E&P venture in Indonesia. In order to achieve the goal, the alternative contract systems considered be chosen were modern RAT, RSC and recent Indonesian PSC system. The background of choosing these alternatives also can be seen in subsection 2.3.2.

The second step of the analysis was to set up three hierarchy structures: the benefit, the cost and the risk structures as shows in Chapter 2 in Figure 2.17, Figure 2.18 and Figure 2.19. Four criteria in benefit hierarchy structure were: Reserve potential (R), Total Reserve Addition in the several years (TRA), Current Production (CP), and Reserve to Production Ratio (R/P). In cost hierarchy structure there were two variables Geology Risk (GR) and Cost Risk (CR, included Technology Risk); while in risk hierarchy structure were Price Risk (PR, included Market Risk), Fiscal Risk (FR), Contract Risk (CoR), and Political Risk (PoR). Definition of criteria in petroleum E&P venture above can be seen in Table 2.12.

Pair wise comparisons of the four possible benefit criteria in investing in petroleum E&P venture in Indonesia was done through scoring these criteria from 1 to 7 in order of its importance ((Note 7 = the most significant/ important/ strong, 6 = very significant/ important/ strong, 5 = significant/ important/ strong plus, 4 = significant /important/ strong, 3 = moderate significant/ important/ strong, 2 = weak significant/ important/ strong, and 1 is the least significant / important/ strong) in generating benefit streams or revenues. Pair wise comparisons in the cost hierarchy valuation was also done through scoring the two cost variables from 1 to 7 in order of its importance in making additional cost or reducing the revenues. Likewise pair wise comparisons in the risk hierarchy valuation was also done through scoring the four risk variables from 1 to 7 in order of its importance in making additional risk or reducing the revenues.

Pair wise comparisons between those alternatives contract system were done through answering two questions of each comparison. As example, the first question in pair wise comparison judgment between RAT and RSC under Indonesia's Reserves (R) condition was:

(a) To reach the objective of attracting petroleum companies to invest in petroleum E&P venture in Indonesia, under Indonesia's Reserves (R) condition, which is more important/desirable RAT or RSC system?

In the case the answer of the first question RAT is more important than RSC, then the second question was:

(b) Under Indonesia's Reserves (R) condition, how much more important/desirable was RAT over RSC (or RSC over RAT, in the case RSC more important than RAT)?

The scoring system used fundamental scale that developed by Saaty (see Table 2.10). These pair wise comparisons were done for all those variables above.

The assumptions taken in this analysis were:

(a) Indonesia was treated as one field of upstream petroleum E&P operation.
(b) The income/profit of the three alternatives fiscal system (RAT, RSC and PSC) had the same amount.
(c) All variables were in the recent Indonesia condition (year 2004).

The respondent’s judgment, opinion and pair wise comparisons between variables and alternatives of petroleum contracts were collected through the same questionnaires and respondents as mentioned in sub section 3.2.1.1 and Appendix A.

The results of the questionnaires were processed with Expert Choice 2000 second edition software from Expert Choice, Pittsburgh PA. First for the benefit structure, it was followed by the cost and then the risk structure. The weight of benefit, cost and risk criteria was calculated through the comparison of the average score of combinations of the benefit criteria, cost criteria and the risk criteria. The rating vector of *Benefits / (Costs x Risks)* was used to weight the corresponding vectors of priorities of the alternatives and to obtain the overall ranking of the alternatives. The highest score of alternative contract system was the most desirable alternative contract system on the petroleum companies’ views in attracting petroleum companies to invest in petroleum E&P venture in Indonesia.

3.4. Methodology to Identify which Aspects of Investment Climate Need to be Improved

Petroleum companies are facing unprecedented pressure to explore and produce new reserves. With demand at an all-time high and increasing pressure to spend profits, companies are looking around the world for opportunities. As already noted in Chapter 1, the prospects and the pace of oil and gas development would depend on the successful efforts to attract the needed capital, Indonesia needs to improve the petroleum contract’s commercial terms and the investment climate.

In order to identify some aspects considered by petroleum companies in the decision-making process to enter petroleum venture in Indonesia and some investment climate aspects/criteria affect their operation in Indonesia, a survey of CEOs of petroleum companies operating in Indonesia and petroleum experts were conducted. The questionnaires and respondents as mentioned in section 3.2.1.1 and

Appendix A were made to collect the CEOs judgments and opinions. Some criteria asked in the questionnaires were:

a) Criteria that were considered in decision making to enter the petroleum venture in Indonesia.
b) Some operation issues that affected the company operation in Indonesia.
c) Understanding on the roles of central, provincial and regional governments under the Laws Number Law 22/1999 on Regional Autonomy and Law 25/1999 on Fiscal Decentralization and the Oil and Gas Law Number 22/2001.
d) Understanding on the roles of Pertamina, BP Migas and Ministry of Energy and Mineral Resources under the Oil and Gas Law Number 22/2001
e) Government – Company Relationship.
f) The attractiveness of existing Indonesian Production Sharing Contract.
g) The improved financial terms of the existing Indonesia's PSC system that petroleum company like to see.
h) The strength of some benefit, cost and risk criteria that were considered in entering in petroleum venture in Indonesia.
i) Pair wise comparisons among benefit, cost and risk criteria and alternatives of petroleum contract system.

The result of the questionnaires were analysed based on the contracts' and companies' judgments and opinions.

CHAPTER 4

EMPIRICAL EVIDENCE, COMMERCIAL PERFORMANCES AND SOME POSSIBLE IMPROVEMENTS

The presentation of the result and finding follows similar sequence to the four objectives of the study as noted in Chapter 1 as follows,

4.1. Commercial performances of Indonesian Production Sharing Contracts,

- 4.1.1. Commercial performances by contract's type and operation years,
  - 4.1.1.1. PSC1 during 30 years operation,
  - 4.1.1.2. PSC2 during 20 years operation,
  - 4.1.1.3. PSC3+IP2 and PSC3+IP3 during 10 years operation.
- 4.1.2. Commercial performances by location,
  - 4.1.2.1. Average western-part vs. average eastern-part of Indonesia,
  - 4.1.2.2. Average onshore vs. average offshore of Indonesia,
  - 4.1.2.3. Indonesia, western-part, eastern-part, onshore and offshore as one field.

4.2. Results of identifying some PSC variables need to be improved as incentives

- 4.2.1. Impact of the application of Incentive Package 5 and Respondents' Proposed Terms on Improvement some PSC Variables of some financial PSC variables,
- 4.2.2. Impact of improvement of some PSC variables,
  - 4.2.2.1. First tranche petroleum,
  - 4.2.2.2. Investment credit,
  - 4.2.2.3. Depreciation method,
  - 4.2.2.4. Contractor production sharing split,

4.2.2.5. Domestic market obligation price

4.2.2.6. Domestic market obligation holiday price,

4.2.2.7. Tax rate,

4.2.2.8. Overall comparison;

4.2.3. Impact of tax consolidation application in frontier areas,

4.2.3.1. Single commercial contract analysis result,

4.2.3.2. Aggregate combined contracts analysis result;

4.3. The most desirable contract system in Indonesia on the view of petroleum company,

4.3.1. The most desirable contract system on the view of *small company* operating in eastern-part of Indonesia,

4.3.2. The most desirable contract system on the view of *medium company,*

4.3.3. The most desirable contract system on the view of *large company*;

4.4. Investment climate of the Petroleum E&P business in Indonesia.

4.1. Commercial Performances of the Indonesian Production Sharing Contracts

4.1.1. Commercial Performances by Contract's Type and Operation Years

As mentioned in sub section 3.1.1 of Chapter 3, samples of the analysis were taken from 24 producing PSCs that had complete and accurate data. PSC1 dominated the number of these 24 producing PSC contracts (63%), followed by PSC2 (29%) and one each from the PSC3+IP2 and PSC3+IP3 types. Out of these 24 contracts, 12 PSC1 contracts had already been operated for more than 30 years, 3 PSC1 contracts between 25 – 29 years, 7 PSC2 between 20 – 24 years, while the PSC3+IP2 and PSC3+IP3 contracts had been operated for more than 10 years each.

Commercial performances analysis of the application of Indonesian PSC system were done for 12 PSC1 contracts during 30-operation years, 7 PSC2 contracts during 20-operation years, one PSC3+IP2 and one PSC3+IP3 contract during 10-operation year each, totalling to 21 PSC contracts. In addition samples were also analysed based on their production type and production rate. The results of these empirical cash flow analyses are shown in Table 4.1 and Table 4.2.

As shown in Table 4.1, based on their production rate, of these 21 producing contracts, five can be categorised as small fields (24%), seven as medium fields (33%), four as large oil fields (19%), four as very large fields (19%) and one as extra large field (5%). These facts show that 57% of PSC producing contracts had production rate up to 50 MBOEPD, 19% had production rate between 50 – 100 MBOEPD, and 24% had production rate over 100 MBOEPD. While based on their production type, eight were categorised as oil fields (38%) and 13 as oil and gas fields (62%).

Table 4.1: 21 samples producing PSC contracts by contract type and production rate

Field Type	PSC1 - 30 years	PSC2 – 20 years	PSC3+IP2 – 10 years	PSC3+IP3 – 10 years	Total	%
Small oil	1	1	1		3	14%
Medium oil	2	1			3	14%
Large oil	2				2	10%
Very large oil						
Extra large oil						
Sub total oil field	5	2	1		8	38%
Small o&g		2			2	10%
Medium o&g	1	2		1	4	19%
Large o&g	1	1			2	10%
Very large o&g	4				4	19%
Extra large o&g	1				1	5%
Sub total o&g field	7	5		1	13	62%
Sub total small field	1	3	1		5	24%
Sub total medium field	3	3		1	7	33%
Sub total large field	3	1			4	19%
Sub total very large field	4				4	19%
Sub total extra large field	1				1	5%
Total	12	7	1	1	21	100%

4.1.1.1. PSC1 during 30 operation years

Based on the type and production rate categorisation, almost all of the 12 PSC1 samples during their 30 operation years were categorised into large and over large fields (8 contracts or 67%). In which three were categorised as large fields (with production rate 50 - 100 MBOEPD), four as very large fields (with production rate over 100 - 200 MBOEPD), and one as extra large fields (with production rate over 200 MBOEPD). The remaining, one is categorised as small field (with production rate below 10 MBOEPD) and three as medium fields (with production rate 10 - 50 MBOEPD).

The mean, maximum and minimum of the lead-time, the range spent from the time of first exploration to the time of first production, of these 12 PSC1 were 5 years, 13 years (mean medium oil field) and 1 year (small oil field) respectively. The long lead-time occurred due to longer exploration needed, delay in production or longer time to develop gas infrastructure. The mean, maximum and minimum of the IRR were 40%, 114% (medium oil and gas field) and 5% (small field) respectively, while for the contractors take values, they were 43%, 81% (small oil field) and 29% (large oil field) respectively. The mean, maximum and minimum of POT were 9.8 years, 16.5 years (mean medium oil field) and 5 years (medium oil and gas field) respectively.

The division of benefits between parties of 75% of these 12 PSC1 samples (9 contracts consisted of two large oil fields, one medium oil & gas field, 6 large and over oil and gas fields) resulted sufficient reward for contractors, contractors got positive NPV@15% during their 30 years of operation, their IRRs were above minimum required rate of return of high-risk investment, with range between 31% to 114%, while their POT ranged between 5 to 12 years and the contractor take values were between 21% to 43%. One sample, the medium oil and gas field, had a very high IRR (114%). This occurred due to short lead-time (3 years) and short POT (5 years). In addition, this contract had relatively high production in its beginning years and its expenditures during the last 15 years of operation were very low, mostly the expenditures for production operation only.

Meanwhile, the remaining 25% of the samples, the one small or marginal field and two medium fields, had negative NPV@15% during their 30 years operation, while their IRR were below 15% and their contractor takes were over 45%. This was due to their small revenues for recovering their expenditures; hence as a result, the remaining revenues (profit oil) to be shared between contractor and GOI were low or none.

Table 4.2: Summary of the result of empirical cash flow analysis of Indonesian PSC by production's type, production rate and operation years

Total contract	Prod. type	Field type	Prod. years	Lead year	Oil&Gas (MBOEPD)	Oil (MBOPD)	Con.Tk %	GOI Tk %	NPV@15% 000 USD	IRR %	POT year
	A. PSC1on 30 years operation										
1	oil	small	29	1	1.0	1.0	81%	19%	(3,085)	5%	10
1	oil	medium	20	10	39.8	39.8	45%	55%	(8,348)	13%	13
1	oil	medium	14	16	33.0	33.0	50%	50%	(13,863)	10%	20
Mean med.oil	2		17	13	36.4	36.4	47%	53%	(11,106)	11%	16.5
1	oil	large	27	3	95.4	95.4	38%	62%	115,035	36%	8
1	oil	large	26	4	60.2	60.2	21%	79%	143,410	45%	9
Mean large oil	2		27	4	77.8	77.8	29%	71%	129,222	40%	9
1	o&g	medium	27	3	31.8	31.7	31%	69%	101,422	114%	5
1	o&g	large	26	4	67.8	54.2	39%	61%	96,236	31%	8
1	o&g	v.large	26	4	133.9	112.7	43%	57%	151,398	37%	9
1	o&g	v.large	25	5	119.9	89.6	31%	69%	190,976	60%	7
1	o&g	v.large	27	3	106.5	59.3	37%	63%	172,632	38%	7
1	o&g	v.large	25	5	111.4	32.3	45%	55%	335,363	38%	10
Mean vlarge o&g	4		26	4	118.0	73.5	39%	61%	212,592	43%	8
1	o&g	ex.large	21	9	325.9	86.3	35%	65%	465,818	38%	12
Mean PSC1-30 years			25	5	94.1	51.6	43%	57%	141,586	40%	9.8
	B. PSC2 on 20 years operation										
1	oil	small	10	10	2.5	2.5	89%	11%	(234,722)	ny	ny
1	oil	medium	5	15	10	10.0	91%	9%	(72,257)	ny	ny
1	o&g	small	12	8	2.1	0.5	89%	11%	(281,157)	ny	ny
1	o&g	small	13	7	1.7	0.5	73%	27%	(13,903)	ny	ny
mean small o&g	2		13	8	1.9	0.5	81%	19%	(147,530)	ny	ny
1	o&g	medium	16	4	25.1	6.4	85%	15%	6,758	17%	5
1	o&g	medium	3	17	17.1	0.8	75%	25%	(27,864)	3%	ny
mean med.o&g	2		10	11	21.1	3.6	80%	20%	(10,553)	10%	ny
1	o&g	large	7	13	65.8	3.8	79%	21%	(42,809)	9%	16
Mean PSC2-20 years			9	11	20.2	4.0	84%	16%	(101,574)	ny	ny
C. PSC3+IP2 on 10 years operation											
1	Oil	Small	8	2	0.2	0.2	88%	12%	(2,970)	nyt*)	4
D. PSC3+IP3 on 10 years operation											
1	o&g	Medium	7	3	15..3	14.4	73%	27%	(29,544)	ny**)	7

*Note: *) IRR: 15% on 4 years operation*
***) IRR: 10% on 9 years operation*

From the view of GOI, the GOI take of the small oil field was very low, only 19%. This occurred due to its small revenues only enough to recover the expenditures; as a result only small profit was shared between GOI and contractor. The others had GOI take relatively high with mean, range between maximum and minimum of 57%, 71% (mean large oil field) and 53% (mean medium oil field) respectively. It suggests that, from the point of view of GOI, the PSC1 generated sufficient income for GOI, except for small and medium oil fields.

To summarise, in general the commercial performance of the PSC1 was very attractive, the division of benefits between parties resulted sufficient rewards for parties, except for one small oil field (with production rate only 1 MBOPD) and two medium oil fields (production rate 39.8 and 33 MBOPD). These facts suggest more incentives are needed in order to increase the commercial performances and the attractiveness of the development of oil fields with production rate below 50 MBOPD.

4.1.1.2. PSC2 during 20 operation years

Based on the type and production rate categorisation, 6 of the 7 PSC2 samples (86% of the samples), during their 20 operation years were categorised into small and medium fields, only one was categorised as large oil and gas field.

The lead-time of PSC2 type was longer than the lead-time of PSC1 with mean, maximum and minimum of 9 years, 13 years (mean small oil and gas field) and 5 years (medium oil field) respectively. During their 20 years of operation, four fields (one small oil field, one medium oil field and two small oil and gas fields) had no IRR and their investment had not broken even yet. Their NPV@15% values were still negative, except for one medium oil and gas field. Their contractor take was high with mean; maximum and minimum of 84%, 91% (medium oil field) and 79% (large oil and gas field) respectively. The higher contractor take was due to their relatively small revenues were still used to recover the exploration expenditures.

The medium oil and gas field had mean IRR of 10%, while the large oil and gas field had lower IRR (9%) due to its longer POT. This might happen due to contractor delaying its production, their production facilities development needed longer time or needed longer exploration time.

From the view of GOI, the GOI take during the 20 years of operation was still low; the mean, maximum and minimum values were 16%, 21% (large oil and gas filed) and 9% (medium oil field) respectively. It shows that the contributions of the PSC2 to GOI income during their 20 years of operation were still low.

It can be concluded that the commercial performances of PSC2 contracts during their 20 years operations were below the PSC1 contracts, the division of benefits between parties resulted insufficient reward for both, due to their small production rates. These facts indicated that there were declining tendencies on productivity and commercial performances of PSC contracts after PSC1 time frame. Moreover, they also suggested that more incentives were needed especially for fields with production rates below 50 MBOPD, in order to increase the commercial performances and increase the attractiveness of the development of those fields.

4.1.1.3. PSC3+IP2 and PSC3+IP3 during 10 years operation

Based on its production type and rate, during their 10 years operation, the PSC3+IP2 sample was categorised as small oil field (production rate 0.2 MBOPD), while the PSC3+IP3 sample was categorised as medium oil and gas field (production rate 15.3 MBOEPD). The samples had short lead-time, the PSC3+IP2 had 2 years and the PSC3+IP3 had 3 years lead-time and their investment had already been paid out in 4 years operation for PSC3+IP2 and in 7 years for PSC3+IP3.

During 10 years operation, the division of benefits between parties did not resulted enough reward for parties, due to their small production rate. Their NPV@15% values were still negative. Although their overall IRR in 2003 were still undefined, the PSC3+IP2 contract already had IRR of 15% on their 4^{th} year of operation while the PSC3+IP3 had IRR of 10% on their 9^{th} year of operation. The decrease on NPV and IRR occurred due to they cashed out high investments, in its last six years for PSC3+IP2 contract and its two years until 2003 for PSC3+IP3 contract.

Understandably, their GOI Take values were still low; their incomes were still used for recovering the expenditures during their first 10 years operation. Although the commercial performances PSC3+IP2 and the PSC3+IP3 during their 10 years operation could not be concluded yet; they show potential commercial performances due to the short lead-time and POT. The facts also indicated that productivity and the commercial performances of the PSC3+IP2 and the PSC3+IP3 contracts were below the PSC1 contracts.

4.1.2. Indonesian Production Sharing Contract Performances by Location

As shown in Table 4.3 and Table 4.4, western-part of Indonesia dominated the total number of PSC contracts signed, totalling to 175 contracts, in which 99 were located offshore and the remaining 76 were located onshore. The other 82 PSC contracts were located in eastern-part of Indonesia, in which 35 contracts were located onshore and 47 were in offshore location.

Western-part of Indonesia also had the highest number of producing contracts, in total 27 contracts or 84% of the total 32 producing contracts. The eastern-part only had only 5 producing contracts. All of these 32 contracts were operated in conventional areas, no one in frontier area.

Moreover western-part also dominated the number the non-producing PSC contracts signed, in total 46 contracts or 63% of the total 73 non-producing contract. The remaining 27 non-producing contracts were located in eastern-part of Indonesia. Similarly, for the terminated contracts, 67% were operated in western-part, while the remaining 33% were located in eastern part of Indonesia.

Table 4.3: Indonesian PSC contracts signed during 1966 – 2003 by location and contract's type

No	Time Frame	West-onshore			West-offshore			West		
	/Con.type	P	NP	Ter	P	NP	Ter	P	NP	Ter
1	PSC1	5		9	9		17	14		26
2	PSC2	5		17	3	1	22	8	1	39
3	PSC3+IP1			1			2			3
4	PSC3+IP2	1	3	8	1	1	7	2	4	15
5	PSC3+IP3	3	2	2				3	2	2
6	PSC3+IP4		10	7		17	10		27	17
7	PSC3+IP5		3			9			12	
	Total	14	18	44	13	28	58	27	46	102
			76			99			175	

No	Time Frame	East-onshore			East-offshore			East		
	/Con.type	P	NP	Ter	P	NP	Ter	P	NP	Ter
1	PSC1	4		5			10	4		15
2	PSC2		1	8		1	6		2	14
3	PSC3+IP1			2		1			1	2
4	PSC3+IP2	1	1	5			5	1	1	10
5	PSC3+IP3		2						2	
6	PSC3+IP4		2	3		15	6		17	9
7	PSC3+IP5		1			3			4	
	Total	5	7	23	0	20	27	5	27	50
			35			47			82	

No	Time Frame	Onshore			Offshore			Total Indonesia			
	/Con.type	P	NP	Ter	P	NP	Ter	P	NP	Ter	Total
1	PSC1	9		14	9		27	18		41	59
2	PSC2	5	1	25	3	2	28	8	3	53	64
3	PSC3+IP1			3		1	2		1	5	6
4	PSC3+IP2	2	4	13	1	1	12	3	5	25	33
5	PSC3+IP3	3	4	2				3	4	2	9
6	PSC3+IP4		12	10		32	16		44	26	70
7	PSC3+IP5		4			12			16		16
	Total	19	25	67	13	48	85	32	73	152	257
			111			146			257		

Note: PSC1 (1965-1975); PSC2 (1976-08/1988); PSC3+IP1 (09/1988 - 02/1989); PSC3+IP2 (03/1989 - 07/1992); PSC3+IP3 (08/1992 - 12/1993); PSC3+IP4 (01/1994 – 2002); PSC3+IP5 (2003 – now)
P = producing; NP = non-producing active; Ter = terminated contract

There were in total 146 PSC contracts located in offshore location, the remaining 111 contracts were located in onshore location. In contrast, the productivity of onshore (59%) contracts was higher than offshore contracts (41%). Overall, 66% of the total 73 non-producing contracts were located in offshore; the remaining 34% were in onshore. Furthermore, 56% of the total 152 terminated contracts were also located offshore while the remaining contracts were located onshore.

Out of 24 producing PSC1 contracts, 13 PSC1 were operated in western-part; two PSC1s in eastern part, seven were operated onshore and eight PSC1 contracts were located offshore. All 7 producing PSC2 were located in western-part, 4 in onshore and 3 in offshore location. On the other hand, one PSC3+IP2 and one PSC3+IP3 contracts were operated in western-part and onshore location.

4.1.2.1. Average Western-part vs. average Eastern-part of Indonesia

The result summary of empirical cash flow analysis Indonesian PSC during 1966 – 2003 period by location can be seen in Table 4.4. Western-part of Indonesia dominated the producing contracts, out of 12 PSC1 during 30 years operation, 10 PSC1 contracts (83%) were located in western-part of Indonesia; the remaining 2 PSC1 contracts (17%) were in eastern-part of Indonesia. There were two medium oil fields, two large oil fields, one large oil and gas field, four very large oil and gas fields and one extra large oil and gas field operated in western-part of Indonesia. On the other hand, only one small oil field and one medium oil and gas field were located in eastern part of Indonesia. Western-part of Indonesia on average could be categorised as very large field with mean production rate of 109.4 MBOEPD, while eastern-part of Indonesia could be categorised as medium field with mean production rate of 16.4 MBOEPD.

In addition, all 7 PSC2, and the PSC3+IP2 and PSC3+IP3 samples were operated in western-part of Indonesia too. These facts show that the contract productivity of the western-part was higher than the productivity of eastern-part. However, the majority of E&P activities were performed in the western-part area, 68% out of total 257 PSC contracts signed during 1966-2003, indicated that petroleum companies had already searched every inch of western-part. Therefore western-part of Indonesia can be categorised as a mature province of petroleum resources.

Table 4.4: Summary of the result of empirical cash flow analysis Indonesian PSC by location

	A. PSC1 30-years				B. PSC2 20-years				IP2-10 ys	IP3-10 ys
	West	East	Onsh	Offsh	West	East	Onsh	Offsh	West-on	West-on
Total contract	10	2	5	7	7	0	4	3	1	1
Total small oil field		1	1		1			1	1	
Total medium oil field	2			2	1			1		
Total large oil field	2		1	1						
Total very large oil field										
Total small oil & gas field					2		2			
Total medium oil & gas field		1	1		2		2			1
Total large oil & gas field	1			1	1			1		
Total very large oil & gas field	4		1	3						
Total extra large oil & gas field	1		1							
Mean Production years	24	28	26	24	9		11	7	8	7
Mean Lead Time	6	2	4	6	11		9	13	2	3
Mean Oil&Gas prod.rate (MBOEPD)	109.4	16.4	106.1	85.2	17.7		11.5	26.1	0.2	15.3
Mean Oil prod. rate (MBOPD)	66.3	16.3	42.3	69.1	3.5		2.0	5.4	0.2	14.4
Mean Contractor take (%)	38%	56%	42%	40%	83%		80%	86%	88%	73%
Mean GOI take (%)	62%	44%	58%	60%	17%		20%	14%	12%	27%
Mean NPV@15% (000 USD)	164,866	49,168	208,586	100,581	(95,136)		(79,041)	(116,596)	(2,970)	(29,544)
Mean IRR (%)	35%	59%	48%	32%	6%		10%	9%	ny*)	ny**)
Mean POT (years)	10	7.5	9	10	11		5	16	4	7

**) 15%(4 years operation)*
***) 10% (9 years operation)*

During their 30 operation-years, the mean of lead-time of PSC1 contracts located in western-part was 6 years, longer than the mean lead-time of the eastern-part (only 2 years). The eastern-part also had longer production years than western-part (28 years vs. 24 years). The mean of contractor take (38%) and IRR (35%) of western-part were lower than the ones of the eastern-part (contractor take of 56% and IRR of 59%). The POT of eastern-part was also shorter than the one of western-part. These facts show that although all areas were commercially attractive, the profitability of contractors operated in eastern-part of Indonesia was higher compared to the ones of western-part of Indonesia. Since all PSC2 and the PSC3+IP2 and PSC3+IP3 were operated in western-part and none in eastern-part, no comparison could be drawn for them.

From the GOI perspective, overall western-part of Indonesia gave more benefit than the eastern-part, due to the higher total producing contracts and the higher GOI take compared to the ones of eastern-part of Indonesia.

Can be concluded, both work areas, western-part and eastern-part of Indonesia, in average, the division of benefits resulted sufficient reward for parties. The fact that western-part of Indonesia became more mature province, suggested that the petroleum E&P investment level in eastern-part of Indonesia must be increased in the future. In order to achieve the increasing level of E&P investment in eastern-part of Indonesia, more lenient contract terms and more attractive incentives were needed for eastern-part of Indonesia and especially for frontier areas.

4.1.2.2. Average Onshore vs. Average Offshore Indonesia

In all, there were 11 producing contracts (5 PSC1, 4 PSC2, one PSC3+IP2, one PSC3+IP3) operated in onshore area, and based on their production rates and types, one was categorised as small oil field, two as small oil & gas fields, 3 as medium fields, one as large oil field, one as large oil field, one as very large and one as extra large oil field. While for the 10 contracts (7 PSC1 and 3 PSC2) operated in offshore area, one was categorised as small oil field, three as medium oil fields, two as large fields and three as very large fields. On average both onshore and offshore locations were categorised as medium field, with mean production rate of 11.5 MBOEPD for onshore and 26.1 MBOEPD for offshore.

The onshore location had shorter lead-time than the offshore area (4 vs. 6 years in PSC1, and 9 vs. 13 years in PSC2) and longer production years (26 vs. 24 years in PSC1 and 11 vs. 7 years in PSC2). From the contractor’s view, the PSC1 contract operated in onshore area during their 30 years operation overall had better mean NPV@15%, mean IRR, mean contractor take and mean POT than ones of offshore area. In contrast, the PSC2 in offshore area have better mean contractor take and mean IRR than the ones of onshore area. Since all PSC2 and the PSC3+IP2 and PSC3+IP3 were operated in western-part and none in eastern-part, no comparison could be drawn for them.

On the other hand, from the GOI's view, offshore areas had slightly higher GOI take than the one of onshore. In contrast, onshore area had slightly higher GOI Take. These facts show that onshore and offshore areas had nearly similar commercial performances.

4.1.2.3. Indonesia, Western-part, Eastern-part, Onshore or Offshore as one field

The results of the cash flow analyses of the commercial performance of each area of Indonesia, including overall Indonesia as one field are shown in Table 4.5. The data were taken from the entire historical financial and non financial data of all PSC petroleum companies operated in each location including producing PSC contracts, non-producing actives PSC and terminated PSC contracts during 1966 – 2003 and combined and assumed as one field operation.

Table 4.5 shows the commercial performance of Indonesia as a whole was very high and gave sufficient income to GOI and sufficient reward for contractor. It had only 4 years of lead-time, 35% contractor's take (or 65% GOI take), 37% IRR (above the minimum required rate of return of high-risk petroleum E&P investment) and 11 years POT as well as 65% GOI Take respectively.

Western part had the longest operation years (37 years); therefore this location also had the highest production and NPV@15%. Eastern part had shorter lead-time (only one year) than the western-part that had 4 years lead-time. Contractor take in western-part (36%) was slightly higher than the one eastern-part (35%), consequently the GOI take of western-part was slightly lower than the one of eastern-part.

Table 4.5: Result of Empirical Cash Flow Analysis Indonesian PSC during 1966 – 2003 period where each location treated as one field

Area/Items	Indonesia	Western-part	Eastern-part	Onshore	Offshore
Start year operation	1967	1967	1970	1968	1967
Operation years	37	37	34	36	37
Production years	33	33	33	33	33
Lead Time	4	4	1	3	4
Oil&Gas prod rate (MBOEPD)	1,455	1,426	29	811	644
Oil prod rate (MBOPD)	974	946	28	527	447
Contractor Take (%)	35%	36%	35%	31%	42%
GOI Take (%)	65%	64%	65%	69%	59%
NPV@15% (000USD)	1,554,511	1,503,472	77,624	1,145,574	558,359
IRR	37%	37%	1% *)	41%	34%
POT (years)	11	11	5	11	10

**) IRR during 1983-2002 periods of 55%*

In 2003 the IRR of western-part was above the minimum required rate of return of high-risk investment (37%) and much higher than the IRR of eastern-part. The eastern-part of Indonesia actually had higher IRR of 55% during 1983 to 2002 period. This was due to in 2002 and 2003 period it cashed out a huge expenditures totalling to 29% of total expenditures during 1966 to 2003 period. In 2003, its IRR decreased to only 1%. In contrast, eastern-part had shortest POT, only 5 years, while for western-part of Indonesia the POT was 11 years. These facts show both western and eastern-part of Indonesia were commercially attractive and give sufficient income to GOI and sufficient reward for contractor.

Comparing the onshore and offshore areas, onshore area had shorter lead-time (3 years) than the one of offshore area (4 years). The IRR of onshore (41%) was above the minimum required rate of return of high-risk investment and higher than the one of offshore (34%). Offshore location had higher contractor take (42%) than onshore location (31%), as a result onshore gave higher GOI take than offshore location. But onshore had slightly longer POT (11 years) than POT of offshore (10 years). These facts show onshore and offshore locations were commercially attractive and give sufficient income to GOI and sufficient reward for contractor.

To summarise, the commercial performances of entire location areas i.e. western-part, eastern-part, onshore, offshore and Indonesia on average and as one field each were attractive; both parties got sufficient rewards. Western-part was a mature province, while in contrast eastern-part had low number contracts signed and high number of unexplored basins. Moreover most of these unexplored basins are located in deep water and remote areas known as frontier areas. Therefore in order to increase the reserves size and production capacity, boosting exploration investment in eastern-part of Indonesia is needed as the first priority. To achieve this, more lenient petroleum contract terms and more special incentives are needed.

4.2. Result of Identifying some PSC Variables Need to be Improved as Incentives

From the 12 PSC1 producing contracts, we obtained 7 representative samples for production type and rate categories. One sample represented case A, the small (marginal) oil field, two samples represented case B, the conventional field oil field, and four samples represented case C, the conventional oil and gas field (four samples). The cases were described below.

1) Case-A represented small (marginal) oil field with production rate below 10 thousand barrels oil per day (MBOPD): one sample with oil production rate of 1 MBOPD.
2) Case-B represented conventional oil field:
   - Case-B1: medium oil field with production rate between 10 and 50 MBOPD: one sample with production rate of 33 MBOPD.
   - Case-B2: large oil field production rate between 50 and 100 MBOPD: one sample with production rate of 95.426 MBOPD.
3) Case-C represented conventional oil and gas field:
   - Case-C1: medium oil and gas production field (between 10 and 50 thousand barrels oil equivalent per day (MBOEPD): one sample with 31.795 MBOEPD oil and gas production.
   - Case-C2: large oil and gas production field (between 50 and 100 MBOEPD): one sample with 67.762 MBOEPD oil and gas production

- Case-C3: very large oil and gas production field (between 100 and 200 MBOEPD): one sample with 106.528 MBOEPD oil and gas production.
- Case-C4: extra large oil and gas production field (over 300 MBOEPD): one sample with 325.932 MBOEPD oil and gas production.

The independent variables were the expenditures, production, and prices profiles of those seven fields above, while the dependent variables were the NPV, IRR, contractor take, POT and GOI take. The PSC variables, i.e., the First Tranche Petroleum (FTP), investment credit (IC), contractor production sharing split (cpss), DMO price (DMPpr), DMO holiday price (DMOhol) and tax rate (taxrate) were the changed variables. Three analyses were drawn for all cases above, the first analysed the impact of the application of Incentives Packages 5 (IP5), the second the application of the CEOs suggestions on improvement some PSC variables and the third the impact of the improvement of some PSC variables. The results are presented as follows.

4.2.1. Impact of the Application of the Fifth Incentive Packages and CEOs Proposed Terms of some PSC variables

4.2.1.1. Respondent's Profile

The questionnaires were sent to 24 petroleum companies presently active in petroleum E&P operation in Indonesia during 1st of March to 31st of August 2004. Eight (30% of total 24 companies) companies returned the questionnaires, and these eight had in total of 45 petroleum contracts in Indonesia. Table 4.6 lists the profile of the respondents. The respondent contracts represented 37% of the 121 total active contracts in Indonesia and 122% of total 37 producing contracts. The numbers of contracts hold by each respondent varied from two to as high as 13 contracts. Of the total 45 contracts, 37 were PSC, 4 were JOB, 1 was JOA and the remaining 3 were TAC contracts. In addition, the questionnaires were sent to five petroleum experts, two returned the questionnaires.

Table 4.6: Company respondents' profile

Company's Respondent profile	Total	Mean	% Total
Total Companies	8		30% of 24 respondents
Total Contract	45	6	37% of total 121 contracts managed by BP Migas 122% of 37 producing contracts
- PSC	37		82%
- JOB	4		9%
- TAC	3		7%
- JOA	1		2%
Total Operation years	244	30.5	
- Above 40 years	1		13%
- 30 - 40 years	4		50%
- Below 20 years	3		38%
Total Annual Expenditures			
- Less than 20 million USD	2		25%
- 20 - 100 million USD	0		0%
- Over 100 million USD	6		75%
Total Annual Production			
- Less than 10 MBOPD	2		25%
- 10 - 50 MBOPD	1		13%
- Over 50 MBOPD	5		63%
- Exploration phase	1		13%
Company Type			
- National Oil Company	1		13%
- Foreign Oil Company	6		75%
- Gas company	1		13%
Operation outside Indonesia	7		88%
Present Upstream activity			
- Onshore	3		
- Offshore	1		
- Onshore-Offshore	4		
- Frontier area	2		
- Deep water 100 m	2		
Present Upstream activity location			
- Western part of Indonesia	7		
- Eastern part of Indonesia	4		

In terms of experiences, all CEO who returned the questionnaires had more than ten years experiences in managing the petroleum company. Also, the company respondents had an overall average of 30.5 years of operation in Indonesia. Consisting of six foreign companies, one national company and one gas company. All of these companies, except one, had worldwide operation. One company had operated in Indonesia for more than 70 years, four companies for more than 30 years, and three companies for less than 20 years.

Location wise, the majority of respondents operated in the western-part of Indonesia; three companies operated in onshore, one in offshore and the remaining four operated in both onshore-offshore locations. In addition, two companies operated in frontier and had two contracts in deep water.

In terms of annual expenditures, 75% of the respondents had budget of more than 100 millions USD, while the remaining 25% had less than 20 millions USD. Furthermore, 63% of the survey respondents had production rate of more than 50 MBOPD, 13% had between 10 and 50 MBOPD, and 25% had less than 10 MBOPD. One was still in exploration phase.

Only two petroleum experts returned the questionnaires. They had more than ten years of experiences in managing the petroleum companies but they were not currently active in managing the petroleum operations. One had educational background in law especially on petroleum contract while the other one had educational background in petroleum economics and law especially on petroleum contract. Their books were used as references of this study.

4.2.1.2. Result and Finding

Five scenarios analyses were drawn, historical PSC1 case (actual case) as base case, Incentives Package 5 for conventional field case (IP5-conv case), Incentives Package 5 for marginal field case (IP5-mar case), the CEOs respondent’s proposed terms with and without depreciation method cases (quest+depre case and quest-nodepre case). Table 4.7 shows the scenarios and assumptions were used in all cases above.

The respondents proposed terms (see Table 4.7) were to decrease the FTP and shared between contractor and GOI; increase the cpss, DMO price as well as the DMO price holiday and investment credit respectively. In addition, the respondent also proposed to allow direct recovery of capital expenditures at the time it spent or essentially no depreciation method was applied. Since most respondents did not state the exact size of their proposed PSC variables changes, we selected the suggestions, which were nearest to the IP5 figure terms as the respondent's proposed terms. The results are presented in Figure 4.1 to Figure 4.7.

Table 4.7: Scenarios, assumptions and result of questionnaires

Small (Marginal) field	**Actual (PSC1)**	**Incentive Package 5 (IP5)**	**Result of Questionnaires**
FTP	Actual	10% all for GOI	10% shared GOI & Con.
Depreciation	5 years DDBL	5 years DDBL	No depreciation
Investment Credit	Actual	102.1400%	102.1400%
- DMO Quantity	25% of production	25% of production	25% of production
- DMO Holiday price	5 years	5 years	10 years
- DMO Price	20ct USD/B	25% of export price	100% export price
Oil PSF: GOI : Con.			
- Post-tax	85 : 15	65 : 35	60 : 40
- Pre-tax	65 : 35	37.5000% : 62.5000%	28.5714%: 71.4286%
Gas PSF: GOI : Con.			
- Post-tax	70 : 30	60 : 40	50 : 50
- Pre-tax	42.3077% : 7.6923%	28.5714% : 71.4286%	10.7143%: 89.2857%
Tax	56% and 48%	44%	44%
Conventional field	**Actual (PSC1)**	**IP5**	**Result of Questionnaires**
FTP	Actual	10% all for GOI	10% shared GOI & Con
Depreciation	5 years DDBL	5 years DDBL	5 years DDBL
Investment Credit	Actual	15.7800%	15.7800%
- DMO quantity	25% of production	25% of production	25% of production
- DMO holiday price	5 years	5 years	5 years
- DMO Price	20ct USD/B	15% of export price	25% of export price
OilPSF: GOI : Con.			
- Post-tax	85 : 15	80 : 20	75 : 25
- Pre-tax	65 : 35	64.2857% : 35.7143%	55.3571% : 44.6429%
Gas PSF: GOI : Contractor			
- Post-tax	70 : 30	65: 35	60 : 40
- Pre-tax	42.3077% : 57.6923%	37.5000% : 62.5000%	28.5714%: 71.4286%
Tax	56% and 48%	44%	44%

As the Figure 4.1 shows, in the small (marginal) oil field case, the application of IP5 for conventional field (IP5 conv case) increased the GOI take from 19% in actual case to 26%. In the other three cases the GOI take decreased to 22%, 7% and 6% for case IP5-mar, quest1 and quest2 respectively. Consequently, the contractor's revenues and other economic parameters (NPV, IRR, contractor take and POT) changed in the opposite direction. The IRR changed from 5% in the actual case to undefined in IP5-conv.case, to 7% in IP5-mar case, to 18% in quest+depre case, and to 19% in quest-nodepre case.

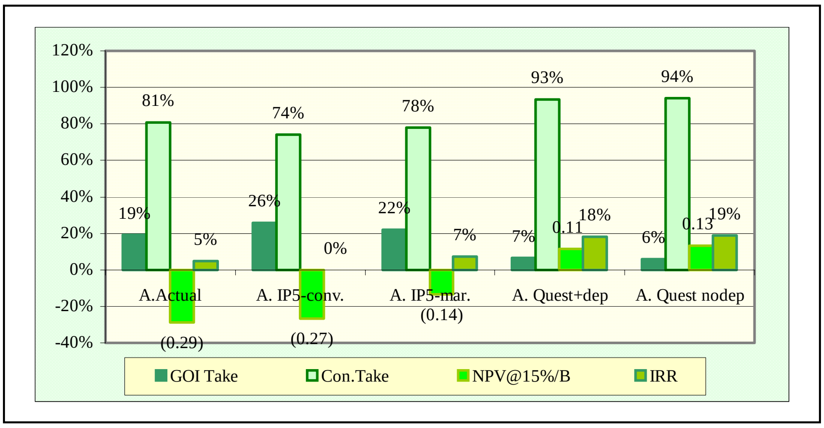


Figure 4.1: Impact of application of IP5 and respondent’s proposed terms on parties’ in small (marginal) field case

The Incentive package 5 for the marginal fields (IP5-mar case) increased the profitability of the contractor with less decrease on GOI income compared to the respondent’s proposed terms, but its IRR was still below the minimum rate of return of small-risk investment. On the other hand, the respondent’s proposed terms with and without depreciation increased the IRR to over the minimum required rate of return of low risk petroleum investment. Although the application of the respondent’s proposed terms in small (marginal) field case gave contractor better profitability by decreasing of GOI income significantly, it must be addressed in order to increase the attractiveness of the small reserves. Otherwise these small (marginal) reserves would never be monetized (lost forever).

There were two contracts used in the cash flow analysis in conventional oil field cases, i.e. case B-1 and case B-2. The case B-1 had an average production of 33,034 BOPD (medium oil field), while the case B-2 had an average production of 95,426 BOPD (large oil field). Figure 4.2 and Figure 4.3 illustrate the cash flow for various scenarios including historical (actual-case), IP5conv-case, quest+depre case and quest nodepre case. From GOI and contractor’s perspective, the actual and the IP5conv-case in case B1 and B2 gave essentially similar results. The impact of changing financial terms was more significant in the cases using the respondent’s proposed terms. For example, in the quest+depre case and quest-nodepre case, the GOI take reduced from 50% to 44% for medium oil field and from 63% to 58% for the large oil field case.

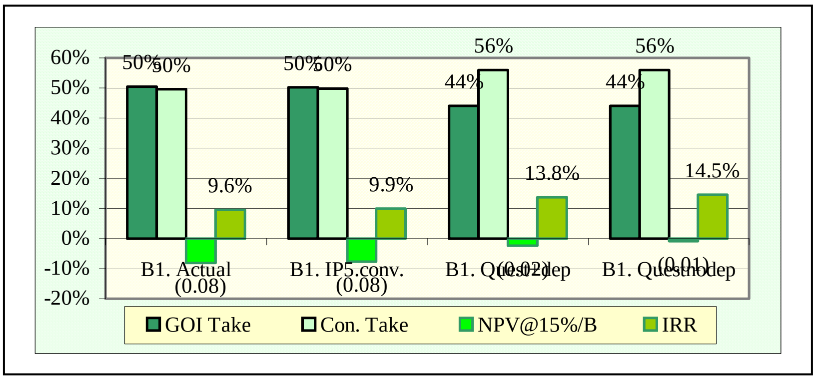


Figure 4.2: Impact of application of IP5 and respondent's proposed terms on parties' in medium oil field case

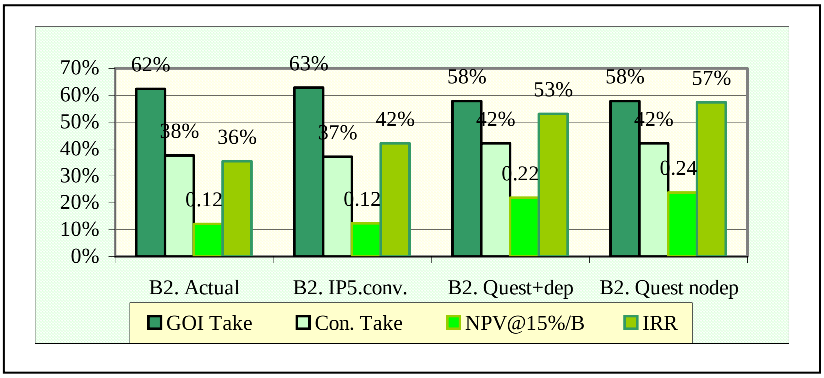


Figure 4.3: Impact of application of IP5 and respondent's proposed terms on parties' in large oil field case

Contractor take was essentially not changed from actual-case to IP5conv-case, but in quest case it increased from 50% to 56% in medium oil field case and from 37% to 42% in large oil field case. Meanwhile the NPV@15% and IRR were slightly increased from actual case to IP5conv-case. However in the questnodepre case, they increased significantly higher than in the quest+depre case. In medium oil case, IRR increased from 9.6% in actual case to 13.8% in quest+depre case and to 14.5% in questnodepre case; while in the large oil case it increased from 36% in actual case to 42% in IP5conv case, 53% in quest+depre case and 57% in questnodepre case.

We summarise that, first the PSC1 terms (actual case) was still attractive for large oil field case; second the impact on the contractor's economic indicators was more significant in the questnodepre case and also more significant in the case of larger production. These facts suggest that recovering the capital expenditures without depreciation was the more desirable incentive option to improve the contractor's economic indicators especially for medium (production rate below 50 MBOPD) oil field development.

In oil & gas field cases, there were four cases, namely Case C-1 through Case-4, representing medium oil & gas field (C1), large oil & gas field (C2), very large oil & gas field (C3) and extra large oil & gas field (C4). Figure 4.4 thru Figure 4.7 show the results of the four cases assuming four different PSC terms: historical (actual-case), IP5conv-case and quest1-case and quest2-case.

From the contractor's perspective, there were increasing tendency on all their economic parameters from actual-case, to the IP5conv-case and all quest-case, except on extra-large field case (C4-case). The impact on the contractor's economic indicators was more significant in the quest-cases, but their impact slightly decreased with increasing size of the field. On extra large oil and gas field, contractor take decreased from 35% on actual case to 34% on IP5conv-case, and similarly for IRR, from 38% to 35%. The ques+depre case and questnodepre case gave similar results, the IRR were increased from IP5-conv-case but still below the actual case (37%), while contractor take are increased to 38% on quest cases. To summarise, the respondent proposed terms did not significantly change the profitability of contractor and GOI income in extra large oil and gas field.

Looking at the IRR, Figures 4.1 to 4.7 show, that the application of PSC1 (actual case) was still attractive since the IRR was over the minimum required rate of return of high risk petroleum investment (over 30%) as suggested by Jones, except for small (marginal) and medium oil field cases. These facts suggest that the respondent proposed PSC terms are needed as incentives to increase the profitability of contractor of oil field with production rate below 50 MBOEPD. Although the PSC1 terms were still attractive for the larger field, due to declining tendencies occurred in the productivity of contracts after the PSC1 time frame, to attract investor, to increase the fifth incentive package (IP5) terms for conventional field (the lowest figures IP5 terms) are needed as incentives for the larger field cases.

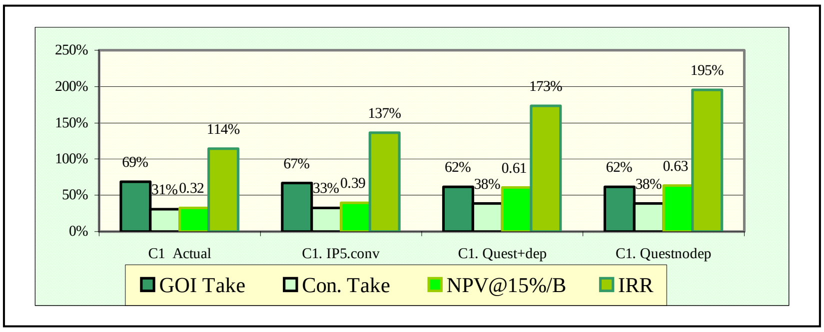


Figure 4.4: Impact of application of IP5 and respondent's proposed terms on parties' in medium oil & gas field case

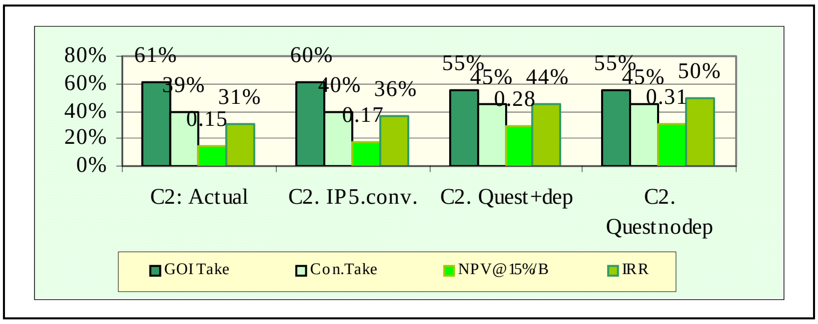


Figure 4.5: Impact of application of IP5 and respondent's proposed terms on parties' in large oil & gas field case

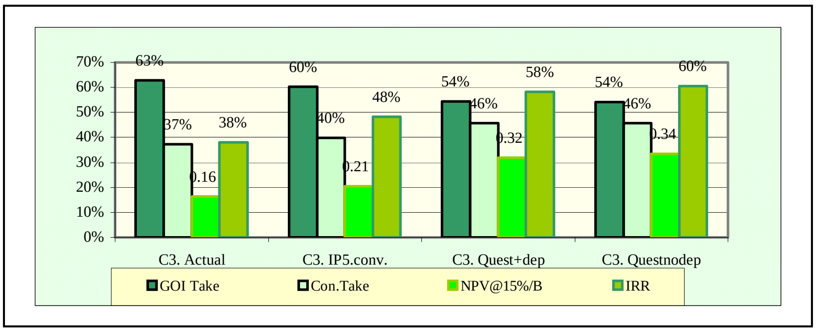


Figure 4.6: Impact of application of IP5 and respondent's proposed terms on parties' in very large oil & gas field case

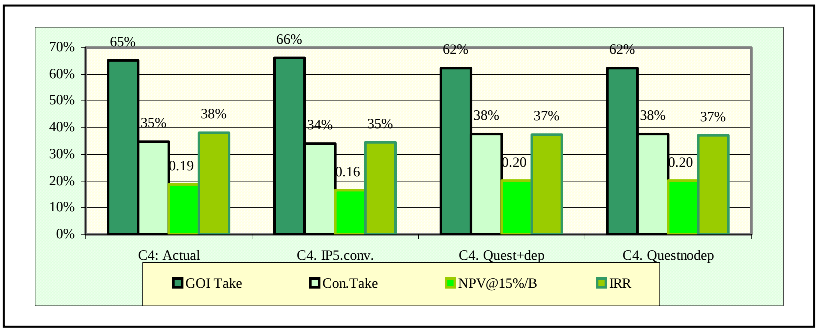


Figure 4.7: Impact of application of IP5 and respondent's proposed on parties' in extra large oil & gas field case

4.2.2. Impact of the Improvement of some PSC Variables

4.2.2.1. First Tranche Petroleum

First Tranche Petroleum (FTP) is a portion of petroleum production amounting some percentage of production taken up firstly before deduction of cost recovery and is shared between GOI and contractor yearly as production sharing split (cpss) specified in the PSC contract. FTP is also taxable. The objective of the FTP is to guarantee the GOI income at first production commences. Logically lesser size of FTP is the better on the investors' view. Under the IP5, the FTP was set up at 10% in sense all go to GOI benefit; it is totally similar to pure royalty payment.

Figures 4.8 thru Figures 4.10 show the impact of FTP size changes in small, medium and large oil fields cases. Figure 4.8 shows the impact of FTP changes in small (marginal) field case. The second group (FTP was shared between contractor and GOI as cpss specified in the contract scenarios) resulted in lower income for the GOI and all the economic parameters (NPV, IRR and POT) of contractor over the first group (100% FTP for the GOI benefit scenarios), even on higher FTP such as 15% and 20% FTP cases. The differences between impact of FTP of first group and the second group in marginal cases were high. As examples, in 10% FTP cases, the IRR in the case in which FTP was shared between parties (15%) was much higher than the IRR in the case in which 100% FTP go to GOI (7%).

On the other hand, the GOI take in 10% FTP shared between parties (16%) was lower than the GOI take in case in which all FTP was for GOI benefit (22%). It occurred due to the small revenues in small (marginal) field case. The more the FTP sizes the more its impact on reducing the revenues to be shared. It can be concluded that the impact of FTP size on profitability of contractor in small (marginal) field case was significant. The provision of 100% FTP for GOI would be a disincentive factor for the development of small (marginal) oil field, and it contradicted the objective of lowering the FTP size under the IP5.

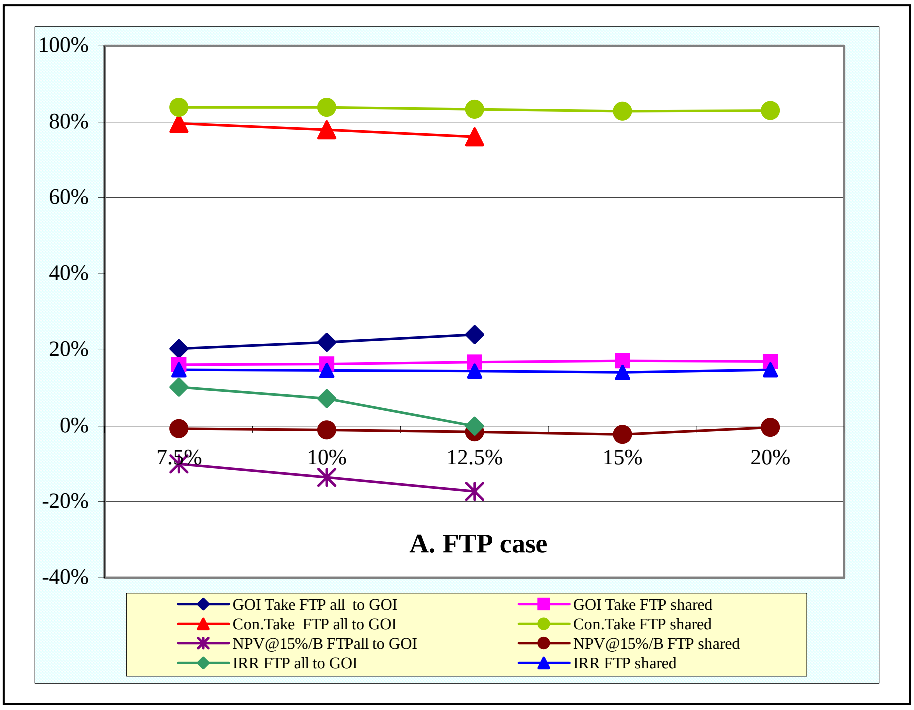


Figure 4.8: Impact of changing FTP size in small (marginal) oil field

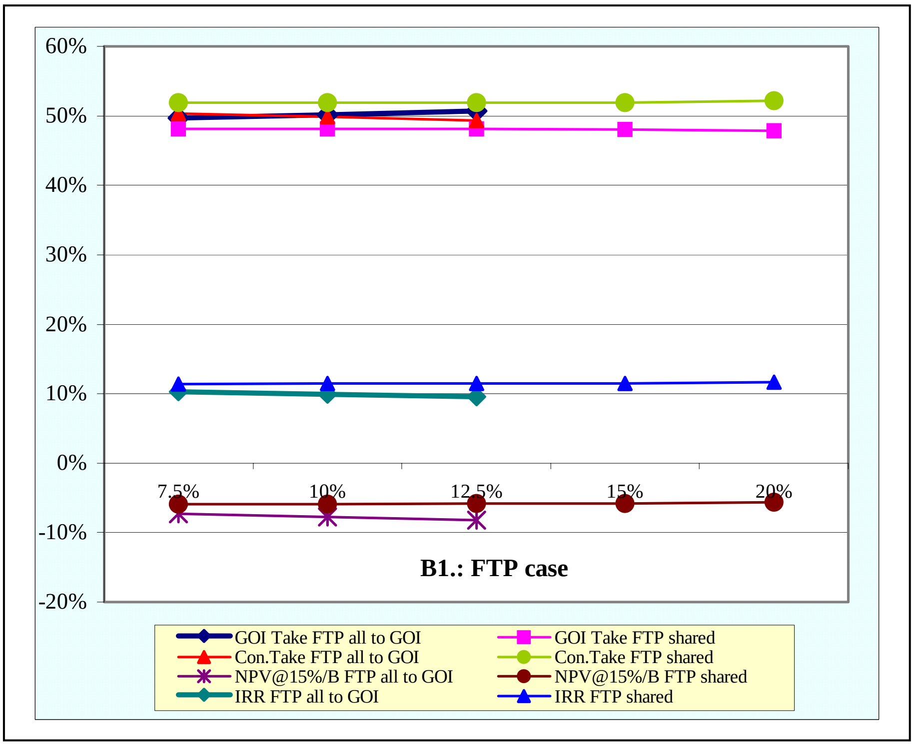


Figure 4.9: Impact of changing FTP size in medium oil field case

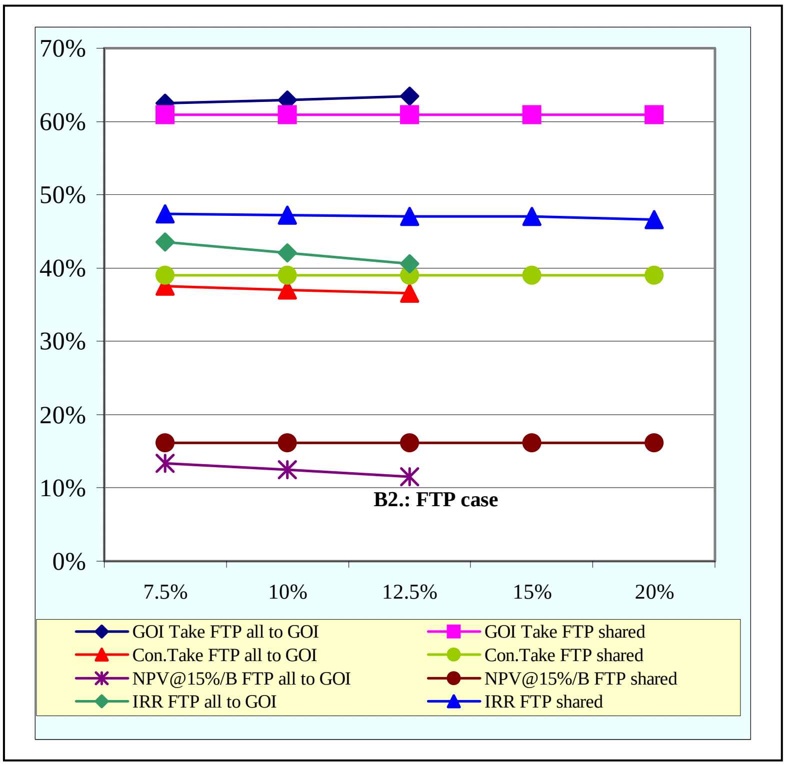


Figure 4.10: Impact of changing FTP size in large oil field case

The impact of FTP changes on oil medium and large oil fields, as shown in Figure 4.9 and Figure 4.10 had similar trend with the impact on small (marginal) field case. From the GOI point of view, the GOI take values increased in all cases in which FTP was 100% for GOI by around 3% to 5% over the case in which FTP was shared between GOI. On the other hand, from contractor's view, all cases in which FTP was shared between GOI and contractor resulted in higher contractor's economic indicators compared to ones of the cases in which FTP was 100% for GOI benefit, even in the cases in which higher FTP were applied (15% and 20%). But the impact was lower than the impact on the small (marginal) oil field case. As an example, in 10% FTP cases, the IRR of the case in which FTP was shared between parties in medium oil field (11%) was slightly higher than the IRR of the case in which 100% FTP was for GOI (10%), while the GOI take of case in which 10% FTP was shared between parties (48%) was slightly lower than the GOI take of case in which all FTP was for GOI benefit (50%).

For the large oil field case, the IRR of the case in which FTP was shared between parties (47%) was higher than the IRR of the case in which 100% FTP was for GOI (44%). It can be concluded that the provision of 100% FTP for GOI would be a disincentive factor for the development of conventional oil field and contradicting with the objective giving incentive by lowering the FTP under the IP5.

Figure 4.11 through Figure 4.14 show the impact of FTP changes in medium, large, very large and extra large oil and gas field. They showed similar trend with marginal field case and conventional oil field, all cases in which FTP was shared between the GOI and contractor resulted in higher contractor's economic indicators compared to the case in which all FTP was for GOI benefit. On the contrary, from GOI point of view, the GOI take increased in all cases in which 100% FTP was for GOI. The impacts in these cases were also lower than in the small (marginal) oil field case. It can be concluded that the provision of 100% FTP for GOI would be a disincentive factor for the development of the conventional oil and gas field and it contradicted with the objective of giving incentive by lowering the FTP under the IP5.

Moreover, compared to other PSC variables, as shown in Figure 4.4 thru Figure 4.14, the strongest impact of decreasing the FTP by 25% was in the small (marginal) field case, while in the larger field cases the FTP ranked as the fourth, except in extra large field case ranked as the third.

To summarise, first, the provision of 100% FTP for GOI would be a disincentive factor for the development of the all field cases, contradicting with the objective of giving incentive by lowering the FTP under the IP5. Secondly, the impact of the FTP changes was significant on the profitability of contractor in small (marginal) oil field case, while the impact on conventional field cases were less than in the impact on small field case. These facts suggest that in order to increase the attractiveness of the development of small (marginal) field, the FTP reduction is needed and must be shared between contractor and GOI.

Bindemann's study showed that during 1966 to 1998 (1999:48-49), royalties in Asia varied between zeros to 12.5% with an average of 4%, on the other hand, in the Eastern Europe; the royalties were between zeros to 17.5% with an average 5%. The average values for the rest of the world were between 7% and 9%. It also showed that net exporter countries charged higher royalties than net importers, and onshore contracts were relatively tougher for the petroleum company than offshore contracts. In fact 91% of all PSC contracts in the dataset had royalties in the four categories of zero, 10%, 12.5% and 20% royalty. Only one contract had more than 20% royalty (Chile, 45%) and only five were below 10%. The 10% FTP of the IP5 (100% go to GOI) can be categorised as the second category of royalty and the size is more than the average of Asia countries.

The FTP is important to secure the GOI income at the beginning years of production and the consistency of the main concept of sharing the production in the PSC system must be honoured; hence the FTP requirement is still needed in Indonesian PSC system. As an incentive for small field case the size of FTP can be reduced below 10% and it must be shared between GOI and the contractor as specified by the production sharing split stated in the PSC contract.

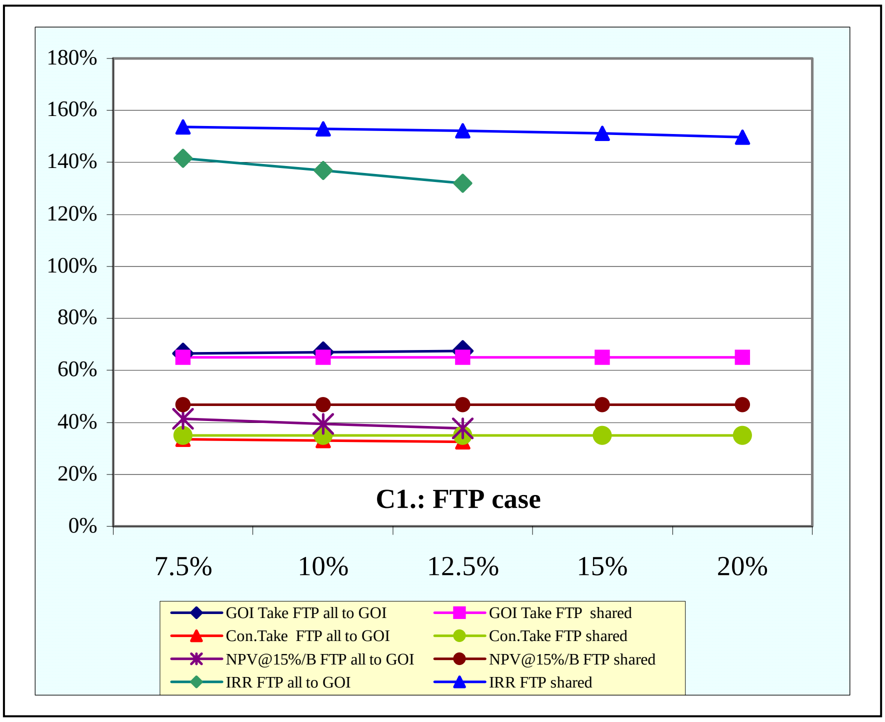
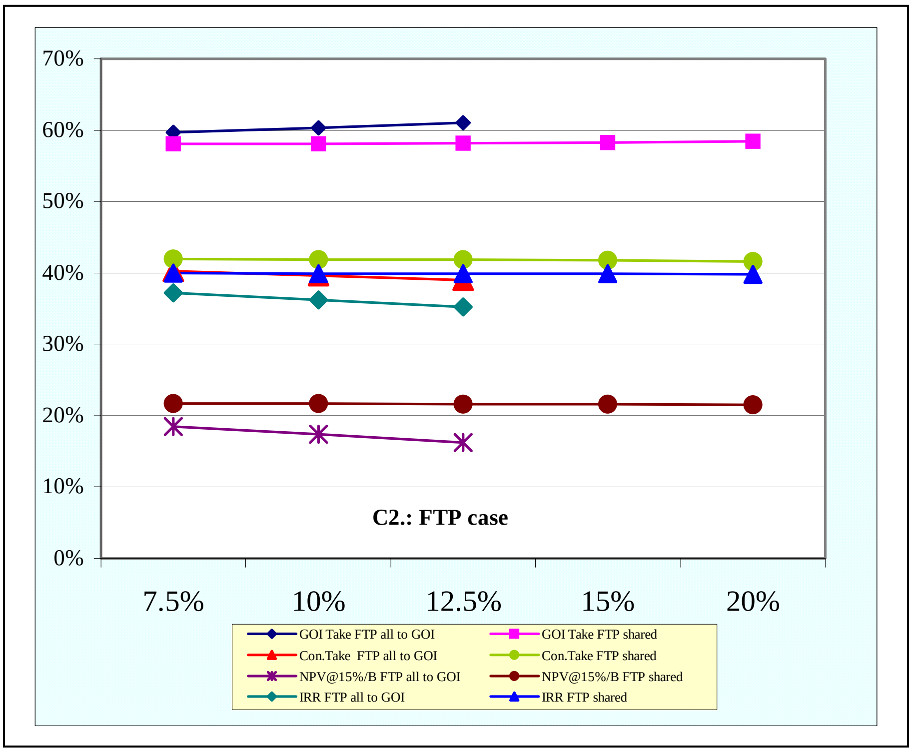
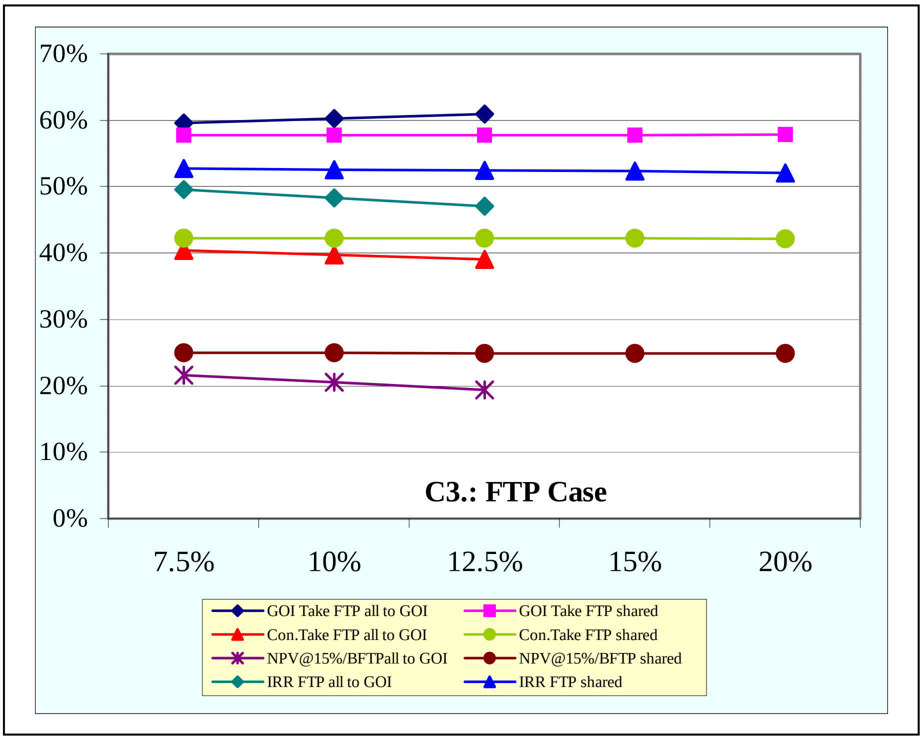


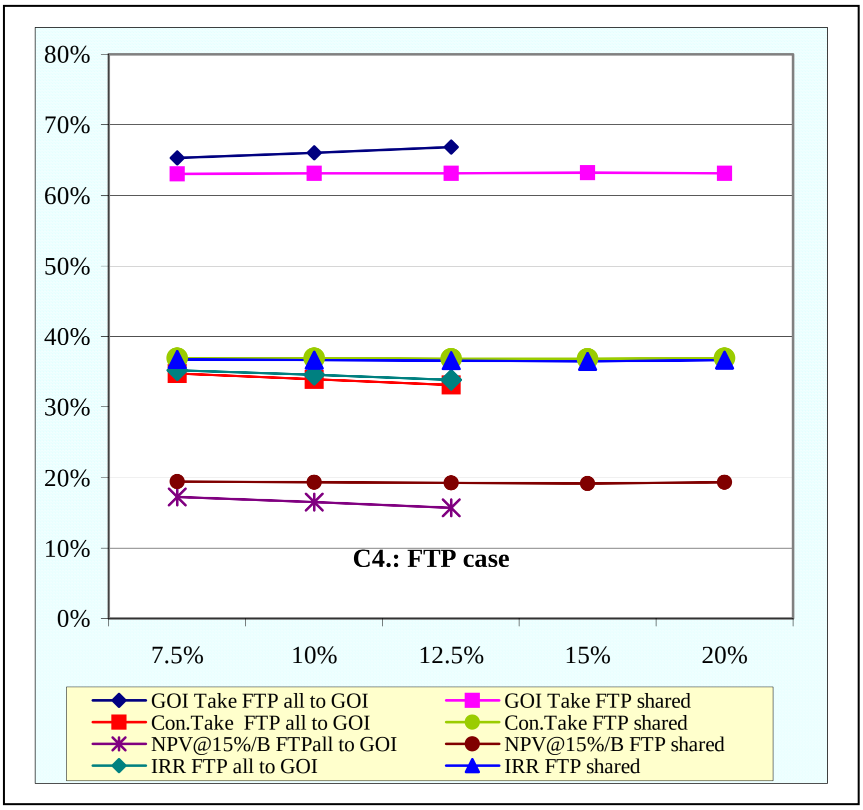
Figure 4.11: Impact of changing FTP size in medium oil & gas field case



4.12: Impact of changing FTP size in large oil & gas field case



4.13: Impact of changing FTP size in very large oil & gas field case



4.14: Impact of changing FTP size in extra large oil & gas field case

4.2.2.2. Investment Credit

In order to identify the impact of the improvement of some PSC variables on the profitability of contractor and GOI income, two models cash flow simulations were drawn on each sample case (small oil field, medium oil field, large oil field, medium oil & gas field, large oil & gas field, very large oil & gas field, and extra large oil & gas field). The first one was the base case cash flow model, in which the IP5 terms were applied. Detail figures of IP5 terms of each PSC variables can be seen in Table 4.7 and samples of the base case cash flow simulation can be seen in Appendix B1 to B7. In the second model, in which one of the six PSC variables was varied while the other variables were kept constant.

The six PSC variables were:

- The investment credit increased by 25% of its IP5 term figures (inv.crdt.up case), in small (marginal) field case from 102.140% as the base case to 127.675%, while in conventional fields (medium, large and over fields) from 15.78% to 19.725%.
- Recovering the capital expenditures without depreciation (nodepre case).
- The contractor production sharing split (cpss) increased by 25% of its IP5 figures (Cpss.up), in small (marginal) field case from 35% as the base case to 44% for cpss oil and from 40% to 50% for cpss gas, while in conventional fields (medium, large and over fields) from 20% to 25% for cpss oil and from 35% to 44% for cpss gas.
- The DMO price increased by 25% of its IP5 figures (DMOpr.up), in small (marginal) field case from 25% of export price as the base case to 31.3% and in conventional fields (medium, large and over fields) from 15% of export price to 18.75%.
- The DMO price holiday increased by 25% of its IP5 figures (DMOhol.up), from 5 years as base case to 6 years.
- The tax rate decreased by 25% below its IP5 figures (tax down), from 44% as the base case to 33%.

In each sample case, the results were compared with the base case in percentage changes, and described in Tornado Diagram.

Table 4.8 shows the results of the analyses, while Tornado Diagrams in Figure 4.15 thru Figure 4.21 show the impacts of the changes of these PSC variables in percentages changes from the base case figures, Figure 4.15 for small (marginal) oil field case, Figure 4.16 and Figure 4.17 for medium and large oil field, while Figure 4.18 thru 4.21 for medium, large, very large and extra large oil and gas field case. The results and findings of these simulation analyses are presented in the following discussions.

Investment Credit allows the contractor to recover an additional percentage of capital costs through cost recovery. The credit is taken out of gross production before recovering operating cost. Increasing the investment credit size is one of possible incentives for the contractor.

In the small (marginal) case, increasing the investment credit increased the IRR significantly, up by 28% over the base case, from 7.3% to 9.3%. The impacts on the larger production were less; in the medium oil field case the IRR only increased by 1.5% and in large oil field case it increased by 0.8%. In medium and large oil & gas fields cases, the IRR increased by only 0.8% at the highest to 0.12% at the least (in extra large oil & gas field) over the base case. The NPV@15% of medium oil field case increased by only 2.4% while for the large oil field case it increased by 1.5% over the base case. In medium and large oil & gas field cases, the NPV@15% increased between 1% and 0.22% % of the base case, while in small (marginal) field, the NPV@15% was still negative. The changes of contractor take and POT in all cases were less than the above variables. These facts show that raising the size of investment credit increased the profitability of contractor significantly only in the small (marginal) field case. This was due to the size of investment credit in small (marginal) field case was much higher than in medium and large field cases (102.14% vs. 15.78%).

From the GOI view, if the size of the investment credit was increased by 25%, the GOI take in small (marginal) field case decreased by 3% of the base case, in medium oil field case it decreased by 0.3% of the base case, while in the remaining cases, it only decreased 0.1% of the base case. Hence, increasing the investment credit size gave minimum impact to GOI income.

Compared to the impacts of other PSC variables, the impact of increasing investment credit was almost the least, except in small (marginal) oil field case. The impact of improvement in investment credit in small (marginal) oil field case ranked as the third strongest, after the impact of recovering the capital expenditures without depreciation. On the contrary, in larger field cases, it ranked as the weakest or the second weakest.

The results suggest that increasing the investment credit can be used as an attractive incentive especially for marginal field and medium field. It can increase the contractor's profitability significantly while at the same time its impact to the GOI income was small. For larger field cases, increasing the investment credit as incentive may not be important, the contractors' profitability was sufficiently high, and its impact was minimal.

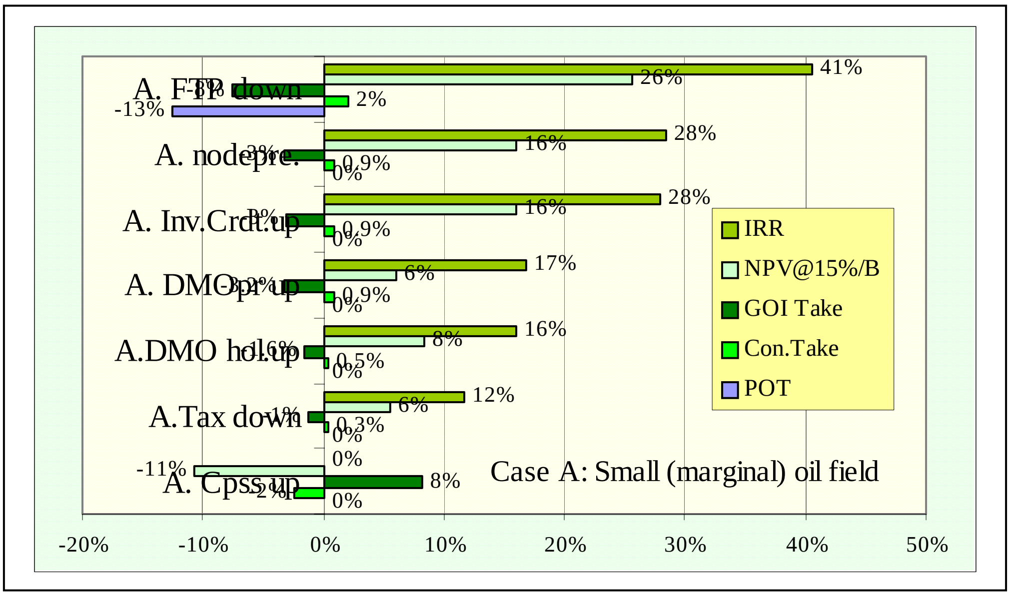


Figure 4.15: Impacts of some PSC variables changes on parties' in small (marginal) oil field case

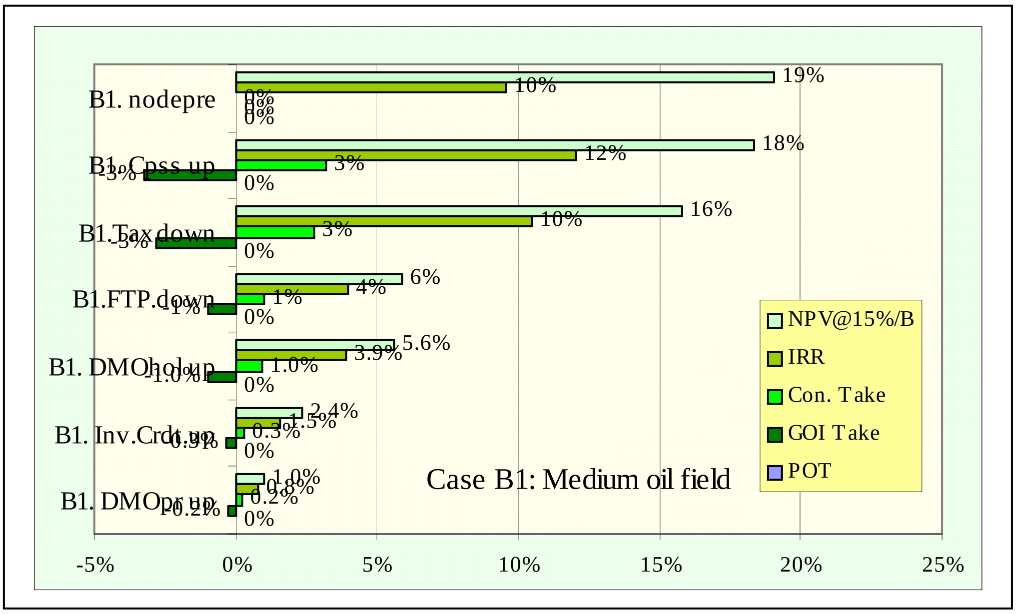


Figure 4.16: Impacts of some PSC variables changes on parties' in medium oil field case

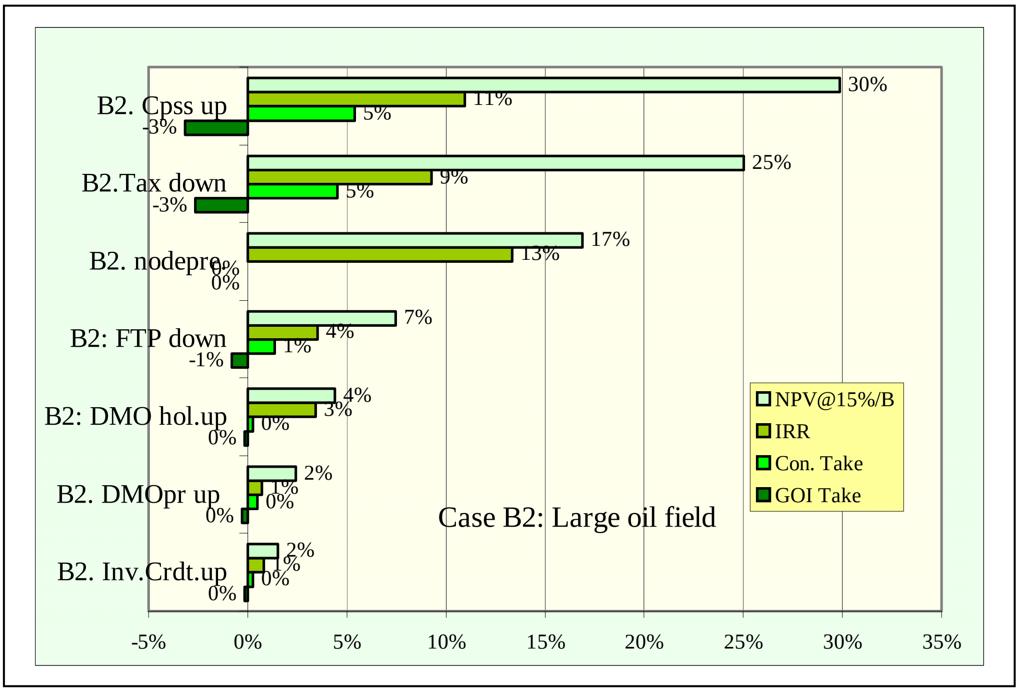


Figure 4.17: Impacts of some PSC variables changes on parties' in large oil field case

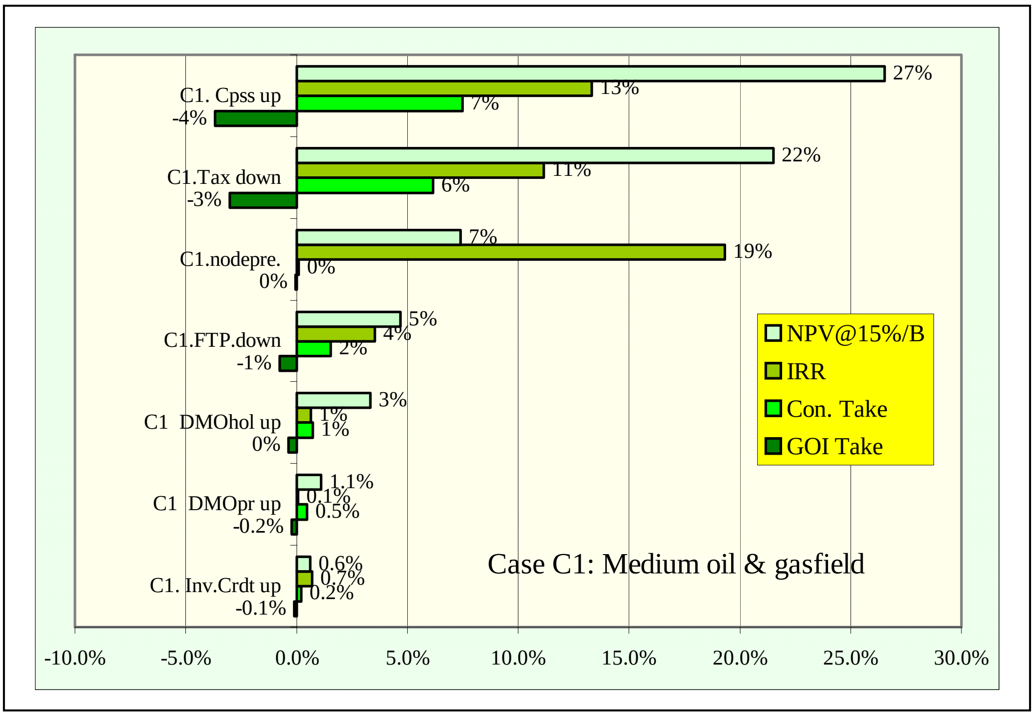


Figure 4.18: Impacts of some PSC variables changes on parties' in medium oil & gas field case

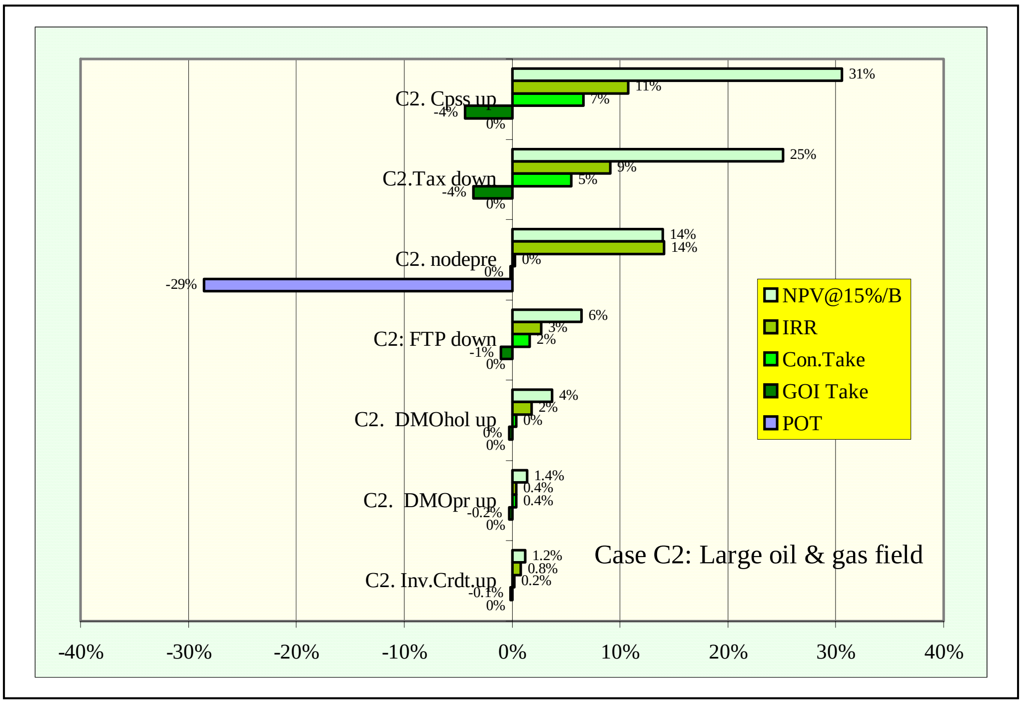


Figure 4.19: Impacts of some PSC variables changes on parties' in large oil & gas field case

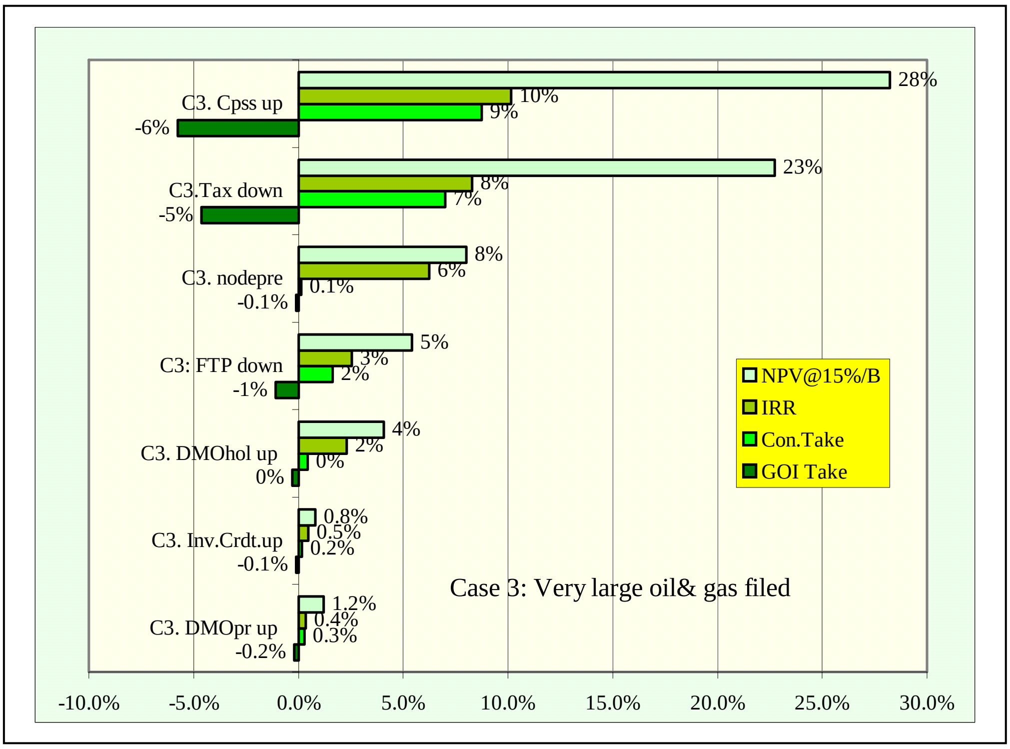


Figure 4.20: Impacts of some PSC variables changes on parties' in very large oil & gas field case

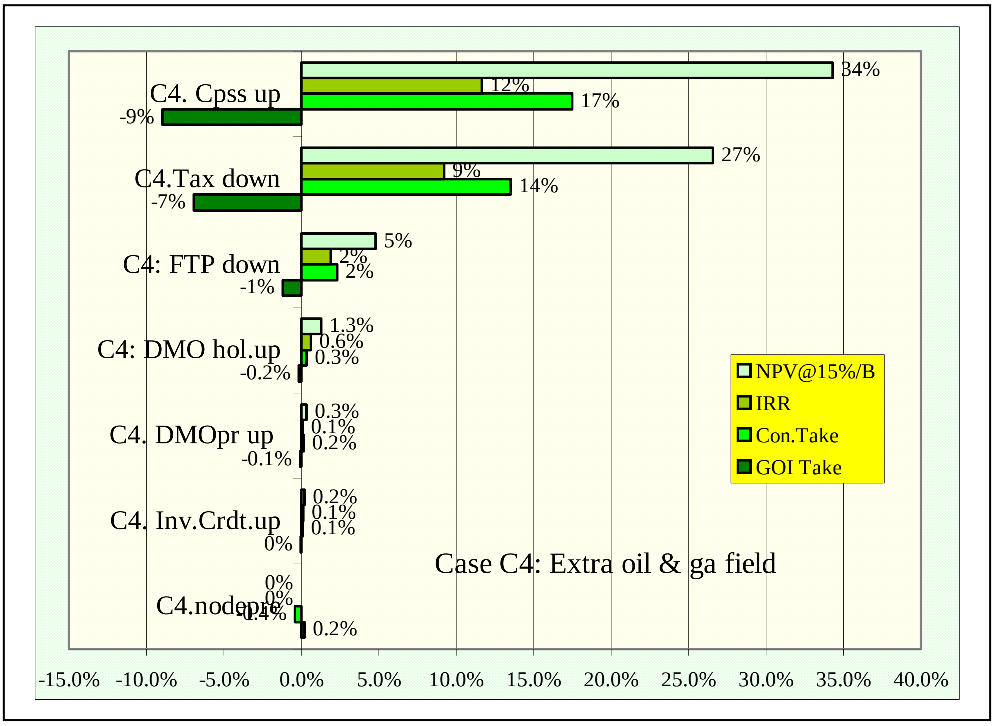


Figure 4.21: Impacts of some PSC variables changes on parties' in extra large oil & gas field case

4.2.2.3. Depreciation Method

The capital expenditures, such as building, transportation facilities, equipment, etc that have useful life beyond the years incurred are recovered in depreciation rate method. In current Indonesian PSC, the recovering of capital expenditures follows five years double declining balance rate method. The shorter the time to recover the capital expenditures means the faster to get the profit. To recover the capital expenditures without depreciation is then a possible incentive to attract investor.

Table 4.8: Impacts of some PSC variables and some Petroleum E&P variables changes on parties'

Base Case (IP5 Terms were applied)							
Result	**Case A**	**Case B1**	**Case B2**	**Case C1**	**Case C2**	**Case C3**	**Case C4**
GOI Take	22%	50%	63%	67%	60%	60%	66%
Con.Take	78%	50%	37%	33%	40%	40%	34%
NPV@15%/B	(0.14)	(0.08)	0.12	0.39	0.17	0.21	0.16
IRR	7.30%	9.90%	42.10%	136.80%	36.20%	48.30%	34.50%
POT	8	19	6	4	7	6	12
FTPt down 25% of its Incentive Package 5 figures							
GOI Take	20%	50%	62%	67%	60%	60%	65%
Con.Take	80%	50%	38%	33%	40%	40%	35%
NPV@15%/B	(0.10)	(0.07)	0.13	0.41	0.18	0.22	0.17
IRR	10%	10.3%	44%	142%	37%	50%	35%
POT	7	19	6	4	7	6	12
Investment Credit up 25% of its Incentive Package 5 figures							
GOI Take	21%	50%	63%	67%	60%	60%	66%
Con.Take	79%	50%	37%	33%	40%	40%	34%
NPV@15%/B	(0.11)	(0.08)	0.13	0.4	0.18	0.21	0.17
IRR	9.30%	10.10%	42.40%	137.80%	36.50%	48.60%	34.60%
POT	8	19	6	4	7	6	12
No depreciation applied in recovering capital expenditures							
GOI Take	21%	50%	63%	67%	60%	60%	66%
Con.Take	79%	50%	37%	33%	40%	40%	34%
NPV@15%/B	(0.11)	(0.06)	0.15	0.42	0.2	0.22	0.16
IRR	9%	11%	48%	163%	41%	51%	35%
POT	8	19	6	4	5	6	12
Contractor production sharing split up 25% of its Incentive Package 5 (IP5) figures							
GOI Take	24%	49%	61%	65%	58%	57%	60%
Con.Take	76%	51%	39%	35%	42%	43%	40%
NPV@15%/B	(0.15)	(0.06)	0.16	0.5	0.23	0.26	0.22
IRR	not yet	11%	47%	155%	40%	53%	39%
POT	8	19	6	4	7	6	12
DMO price up 25% of its Incentive Package 5 figures							
GOI Take	21%	50%	63%	67%	60%	60%	66%
Con.Take	79%	50%	37%	33%	40%	40%	34%
NPV@15%/B	(0.13)	(0.08)	0.13	0.4	0.18	0.21	0.17
IRR	8%	10.00%	42%	137%	36%	49%	35%
POT	8	19	6	4	7	6	12
DMO holiday price's up 25% of its Incentive Package 5 figures							
GOI Take	22%	50%	63%	67%	60%	60%	66%
Con.Take	78%	50%	37%	33%	40%	40%	34%
NPV@15%/B	(0.12)	0.08	0.13	0.41	0.18	0.21	0.17
IRR	8%	10%	44%	138%	37%	49%	35%
POT	8	19	6	4	7	6	12
Tax rate down 25% of its Incentive Package 5 figures							
GOI Take	22%	49%	61%	65%	58%	57%	61%
Con.Take	78%	51%	39%	35%	42%	43%	39%
NPV@15%/B	(0.13)	(0.07)	0.16	0.48	0.22	0.25	0.21
IRR	8%	11%	46%	152%	40%	52%	38%
POT	8	19	6	4	7	6	12
Oil & Gas price up 25% of their historical figures							
GOI Take	30%	57%	68%	71%	65%	64%	67%
Con.Take	70%	43%	32%	29%	35%	36%	33%
NPV@15%/B	0.05	(0.04)	0.19	0.53	0.26	0.29	0.23
IRR	17%	12.7%	53%	171%	44%	57%	40%
POT	6	17	6	4	7	6	12
Expenditures up 25% of their historical figures							
GOI Take	10%	41%	57%	62%	55%	56%	67%
Con.Take	90%	59%	43%	38%	45%	44%	33%
NPV@15%/B	(0.42)	(0.13)	0.09	0.35	0.13	0.17	0.23
IRR	not yet	7.0%	32%	103%	29%	40%	40%
POT	10	20	8	5	8	6	12
Production down 25% of their historical figures							
GOI Take	10%	39%	55%	61%	54%	54%	64%
Con.Take	90%	61%	45%	39%	46%	46%	36%
NPV@15%/B	(0.43)	(0.15)	0.08	0.34	0.09	0.16	0.13
IRR	not yet	6.0%	29%	95%	24%	37%	28%
POT	11	20	8	5	8	6	13

In the small (marginal) field case, the case in which the capital expenditures were recovered straight on the year they are cashed-out without depreciation increased the contractor's IRR significantly, by 28% above the base case. In the higher production rate case, recovering capital expenditures without depreciation gave less impact on IRR. In medium oil field case it increased by 10% above the base case, in large oil field case by 13%, in medium oil & gas field case by 19%, in large oil & gas field case by 14%, in very large oil & gas field case by 6% above the base case, and in extra large oil & gas field, the IRR did not increase (0%). These tendencies also occurred on NPV@15% changes. The contractor take only increased by 0.9% in small (marginal) field case and even less on higher fields cases, by between 0.2% to zero, except in extra oil & gas field case, where it decreased by 0.4% below the base case.

As for the impact on the GOI, recovering the capital expenditures without depreciation decreased the GOI take by 3.3% below the base case in small (marginal) field case, remained the same in medium oil field, decreased by between 0.2% to zero in higher fields cases, except in extra large field case where the GOI take increased by 0.2% above the base case.

Compared to the impact of other PSC variables changes, recovering capital expenditures without depreciation method had more impact on contractor's profitability than investment credit changes. In small (marginal) oil field case as the second and in medium oil field case it ranked as the strongest variable, while in larger field cases it ranked as the third, except in extra large field where it ranked the least.

Hence, it can be concluded that recovering the capital expenditures without depreciation can be utilised as incentive, especially for small (marginal) field and medium oil fields cases developments.

4.2.2.4. Production Sharing Split

Sharing the production after FTP and cost recovery payment is one of the main terms in PSC system. Profit oil or profit gas is defined as the remaining revenues after deduction of FTP and cost recovery. This profit is split between the contractor and the GOI as production sharing split as stated in the contract. Before 2003 the oil production split in conventional oil & gas field was 85/15, while in frontier (marginal) field it was 70/30 in favour of GOI. Under the IP5 the oil production sharing splits were increased to varied from 80/20 to 65/35 depending on the geological conditions. As for gas, before 2003 the gas production sharing split in conventional field was 70/30 and in small (marginal) field it was 60/40 in favour of GOI. Currently, under the IP5 the gas production sharing split was 65/35 in favour of GOI. The contractor share from profit oil is also subjected to taxation. Increasing the contractor's production sharing split (cpss) is a possible incentive to investor, since logically it can increase the profitability of investor. But, on the other hand, it will decrease the GOI income.

As the base case, the cpss in the IP5 conventional oil field base case (IP5-conv-case) was assumed to be 20%, while in the IP5 small (marginal) oil field base case (IP5-mar-case) it was assumed to be 35%. Increasing cpss 25% above the base case, the cpss became 25% in conventional field case and the cpss became 44% in small (marginal) field case.

Table 4.8 shows that the contractor's IRR of small (marginal) oil field base case and medium oil field base case were below the minimum required rate of return of low-risk petroleum investment (15%) and their NPV@15% were negative. In the larger field cases their IRRs were above the minimum required rate of return of high-risk petroleum investment (over 30%) and their NPV@15% were positive. These facts suggest that increasing the cpss as incentives is needed only for small and medium oil development.

The impact of increasing cpss 25% of the base case in small (marginal) field case did not increase the profitability of contractor; on the contrary the IRR of the contractor decreased from 7% in the base case to undefined, since the contractor still got negative income. The contractors take decreased by 2% below the base case. The small production size in small (marginal) field made the revenues were still used to recover the expenditures; therefore the remaining production to be shared was very small or none.

On the contrary, in medium, large, very large oil and oil & gas field cases, increasing the cpss 25% of the base case significantly increased the profitability of contractor. The NPV@15% increased by between of 18% to 34%, the IRR increased by between10% to 13%, while the contractor take increased by the range of 3% to 17% above the base case.

The GOI take in small (marginal) field case increased by 8% above the base case as the impact of increasing the cpss 25% above the base case. While in medium, large, very large, extra large oil& gas fields cases, the GOI take decreased by in the range of 3% to 9% (extra large oil & gas field case) below the base case, when the cpss was increased by 25% above the base case. These figures were below the increases in NPV@25%, IRR and contractor take. To summarise, in small (marginal) field increasing cpss did not increase the profitability of contractor; while in the other cases it increased the profitability of contractor.

Increasing the cpss was the most powerful variables to increase the profitability of contractors; in larger field cases it ranked as the strongest, except in small (marginal) field case where it ranked as the least. It happened due to the small remaining production to be shared between contractor and GOI (gross revenues from production after FTP payment and recovering the expenditures) in small (marginal) field case. That is why increasing the cpss had less impact on the profitability of contractor.

Compared to other countries, the Bindemann data set during 1966 – 1998 period (Bindemann, 1999:50 - 51) showed that the minimum cpss figure in IP5 was below the minimum cpss average of Asia countries, but its maximum cpss was slightly above the maximum cpss average of Asia countries. The maximum and minimum average cpss of Asia countries ranked as the third toughest cpps compared to other region. In addition, currently the maximum cpss tended to increase in all regions except in Middle East where from an average of 27%, it declined significantly lower than elsewhere. Also, exporter countries offered less favourable sharing split to the contractor than importer countries Therefore to attract investor, increasing cpss still need to be offered as attractive incentives especially for small and medium oil field development. While for larger field cases, the cpss of fifth incentive package (IP5) figure was still attractive, since the resulting contractor IRR was above the minimum required rate of return of high risk petroleum investment (over 30%).

4.2.2.5. Domestic Market Obligation Price

Government specifies a percentage (25%) of the contractor's profit oil should be sold to the government at discounted price; it is called Domestic Market Obligation (DMO). The goal of DMO is to give security for the oil and gas domestic supplies for the country. Under the IP5 the price of DMO (DMO-price) was set at 15% of export price for conventional field and 25% for small (marginal) field. Increasing the DMO price is one possible incentive that can be offered.

In the small (marginal) oil field case, increasing the DMO price by 25% increased the IRR by 17% above the base case, increased the NPV@15% by 6% and increased the contractor take by only 1% above the base case. It did not have impact on the POT, and the GOI take decreased by 3% below the base case.

On the other hand, increasing DMO price by 25% gave less impact on the medium, large, very large and extra large oil & gas field cases. The NPV@15% increased by on the range of 0.3% to 2% above the base case, the IRR on the range of 0.1% to 0.4%, and the contractor take and contractor share on the range 0.1% to

0.5% above the base case. The GOI take decreased less than the sizes of the contractor take increase, on the range of 0.2% to 0.3% below the base case.

Compared to other PSC variables, the impact of increasing the DMO price was less, except in small (marginal) field case where it ranked as the third strongest on the economic parameters of contractors. While in the larger fields cases it ranked as the weakest or the second weakest. It suggests that increasing the DMO price is an attractive incentive only for small (marginal) field development.

4.2.2.6. Domestic Market Obligation Holiday Price

As the base case, the DMO holiday price was set up 5 years and then increased by 25% to 6 years. The results can be seen in Figure 4.8(a) to Figure 4.8(g). In marginal field case, increasing the DMO holiday price from 5 to 6 years increased the IRR by 16% above the base case while the contractor take increased by only 0.5%. On the other hand, the GOI take decreased by 1.6% below the base case.

In conventional field cases, when the DMO holiday price increased to 6 years, the impacts were lower than the impacts in small/marginal field case. The IRR increased only by 3.9% in medium oil field, by 3.4% in medium oil & gas field, by 0.7% in large oil & gas field, by 2% in large and very large oil & gas field and only by 0.6% in extra large oil & gas field. The NPV@15% increased by 5.6% in medium oil field, by 4.4% in large oil field, by 3.3% in medium oil & gas field, by 4% in large and very large oil & gas field and only by 1.6% above the base case in extra large oil & gas field cases. The impacts on contractor take were also lower, on the range 1% to 0.3% over the base case. The GOI take decreased on the range 1% to 0.2% below the base case. There were declining tendency of the impacts as the field got larger.

Compared to other PSC variables, the impact of increasing the DMO holiday price was less and ranked as the fourth strongest. These facts suggest that increasing

DMO holiday price can be used as incentives especially for small (marginal) field development, with less impact on GOI income.

4.2.2.7. Tax Rate

The contractor tax liabilities refer to the relevant tax law since the tax in general may be found under a separate set of laws. Decreasing the tax rate will logically increase the contractor incomes, and therefore will increase the profitability of contractor.

Decreasing the tax rate in small (marginal) field case increased the IRR by 12% above the base case while the contractor take only increased by 0.3%. On the other hand, the GOI take decreased by 1.2% below the base case. These lower impacts of decreasing tax rate in small (marginal) field was due to the small revenues from the small field was only enough for recovering the exploration and development costs. The remaining revenues (profit oil) for contractor were small and the cost recovery is free from tax payment. Therefore in small (marginal) field case, the changes on tax rate only gave low impact on the size of tax payment and contractor income.

There were increasing tendency on NPV@15% changes with the increase in field size. The NPV@15% increased on the range of 16% (in medium oil field case) to 27% (in extra large oil & gas field case) above the base case. In conventional field cases, the IRR increased on the range of 10% (in medium oil field case) to 8% (in very large oil & gas field case) above the base case. The impacts on contractor take were less than the impacts on NPV@15%, on the range of 3% to 14% above the base case. On the other hand, GOI take decreased on the range of 3% (medium oil filed case) to 7% (extra large oil 7% gas field case).

Compared to other PSC variables, the impacts of decreasing of tax rate ranked as the second strongest after the increasing the cpss, except in small (marginal) field case; although it increased the IRR by 12% above the base case, it still ranked as the second weakest. These facts suggest that decreasing the tax rate can be used as incentive in the development of small (marginal) and medium field cases. On the contrary, for large and extra large fields, this incentive is not needed since the IP5 terms for conventional field still gave sufficient profitability for contractor.

4.2.2.8. Overall Comparison of the Impact of some PSC's Variables Changes

As shown in Figure 4.15 in the small (marginal) oil field case the IRR was the most sensitive variable with changes ranged between 24% to 12%, followed by NPV@15%/B, GOI take, and contractor take as the least sensitive variable (range between 0.9% to minus 2% below the base case). On the other hand, among PSC variables be compared, the increase in FTP, investment credit and recovering capital expenditures without depreciation gave the three strongest impact compared to other variables in small (marginal) field case; they increased the IRR by 41% in FTP and the other of 28% above the base case. Their investment did not pay out yet. Increasing cpss 25% above the base case increased the GOI take by 8% above the base case. It happened since, due to its small revenues, the remaining revenues to be shared (after FTP payment and cost recovery) was small, none or still minus.

While on the larger field cases, the NPV@15%/B was the most sensitive variable, followed by IRR, contractor take and GOI take as the least sensitive variable. In these larger field cases, the POT did not change, except in large oil and gas field case, the POT decreased by 29% below the base case when no depreciation method on recovering the capital expenditures was applied. This fact occurred since capital expenditures were cashed out during the beginning years of operation; hence recovering the capital expenditures straight without depreciation method made the POT time shorter.

Among PSC variables be compared, the increasing cpss, reducing the tax rate and recovering the capital expenditures without depreciation method in larger field cases gave the three highest impacts on the changes of the contractor and GOI economic parameters, on the range of changes of 34% to 19%. While the other variables, reducing the FTP, increasing the DMO price, increasing the DMO holiday price time and increasing the investment credit gave less impact.

To summarise, the Fifth Incentives Package (IP5) that commenced by GOI in 2003 was commercially attractive for the field with production rate above 50 MBOPD. Hence more incentives are needed for the fields with production rate below 50 MBOPD. The recommended incentives to be offered to attract investor for the field with production rate below 10 MBOEPD (in the order of their impact strengths) are: reducing the FTP, recovering the capital expenditures without depreciation, increasing the investment credit, increasing the DMO price, DMO holiday price, reducing tax rate and increasing the contractor production sharing split from the highest figures of the Fifth Incentives Package. For the oil field with production rate between 10 – 50 MBOPD, the recommended incentives are increasing contractor production sharing split, reducing the tax rate from the lowest figures of the Fifth Incentives Package and recovering the capital expenditures without depreciation method. The proposed respondents' terms can be considered be applied.

4.2.2.9. Impact of Increasing the Oil and Gas Prices, Increasing the Expenditures and Reducing the Production Size

The impact of increasing the oil and gas prices by 25% over the base case is shown in Figure 4.22. The impact of increasing oil price was the highest in small (marginal) field case. It gave significant increased on both parties income. The increases in both contractor's IRR (134%) and NPV@25% (117%) were much higher, almost 3.7 times more than the increase in the total GOI Take (only 37%). The impacts on larger field cases were lower, but the trend was similar to the trend on small (marginal) oil case. The impacts on GOI income changes were always less than the impacts on profitability of contractors. This fact shows that, in percentage basis, the contractor obtained more profit than GOI when oil price increased. It suggests that balancing the reward between contractor and GOI in case of high oil price is needed. The treatment of increasing oil prices clause should be included in the contract; we suggests the application of sliding method on production sharing split based on the oil and gas prices.

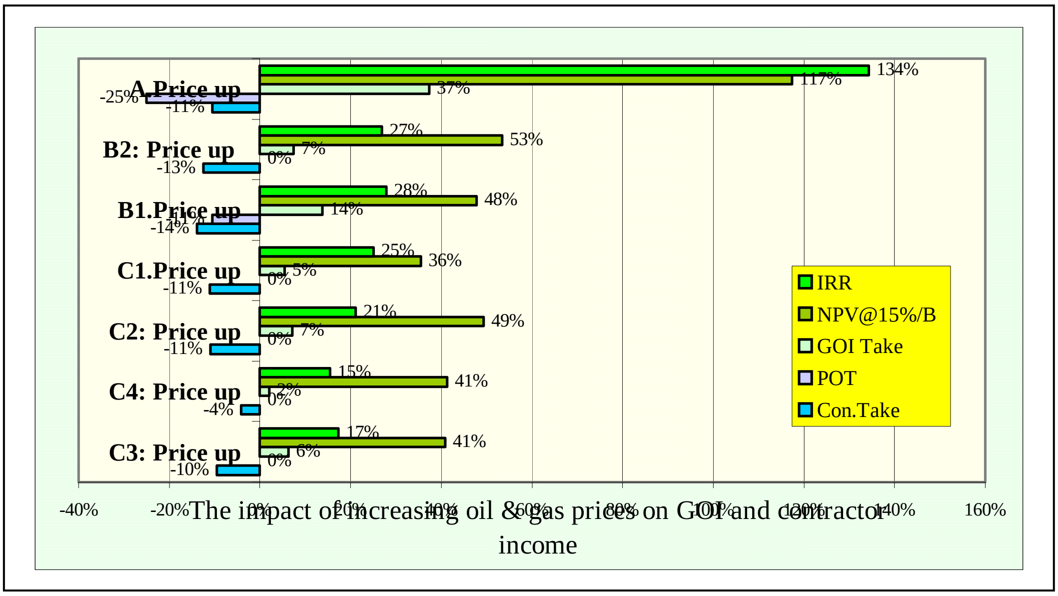


Figure 4.22: Impact of increasing oil & gas prices

Figure 4.23 shows the impacts of increasing the expenditures by 25% to both contractor and GOI. Increase in expenditures resulted in significant reduction on both the profitability of contractor and GOI income. The two most sensitive variables were the NPV@25% and the IRR. The impact on the GOI income was lower than the impact on contractor’s profitability, i.e., the reduction on GOI income, in percentage basis, was lower than the reduction on contractor’s profitability. There was also a trend showing that the impact in percentage basis became less, as the field size got larger.

Impact of decreasing production by 25% below the base case is shown in Figure 4.24. The two most sensitive economic variables were similar, the NPV@25% and the Total GOI income. The trends of its impact were similar to the case of increasing the expenditures. In percentage basis, the impact affected the contractor more than it affected the GOI, and the impact became less, as the field size got larger.

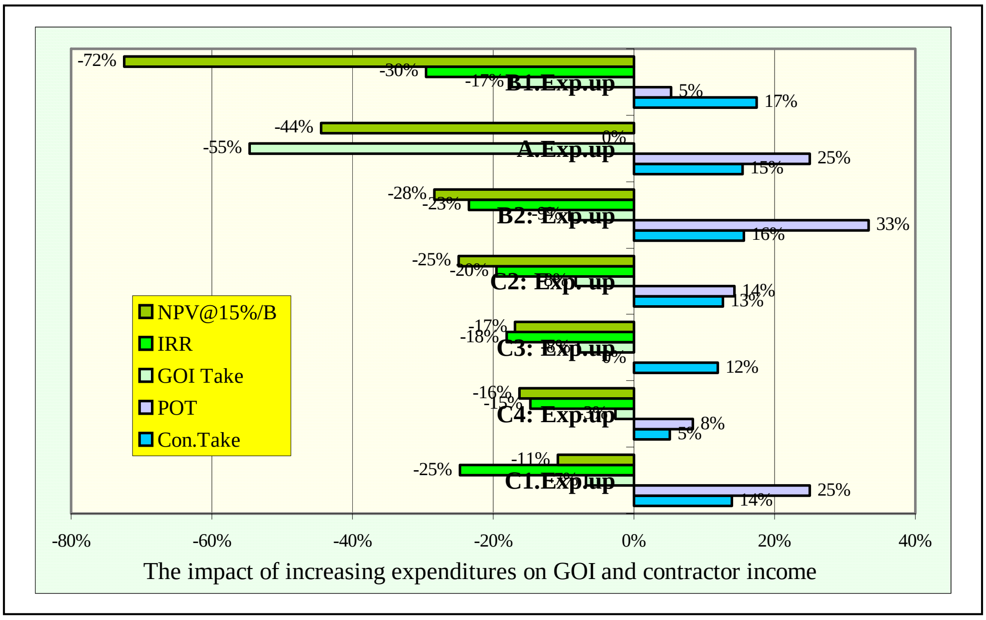


Figure 4.23: Impact of increasing expenditures

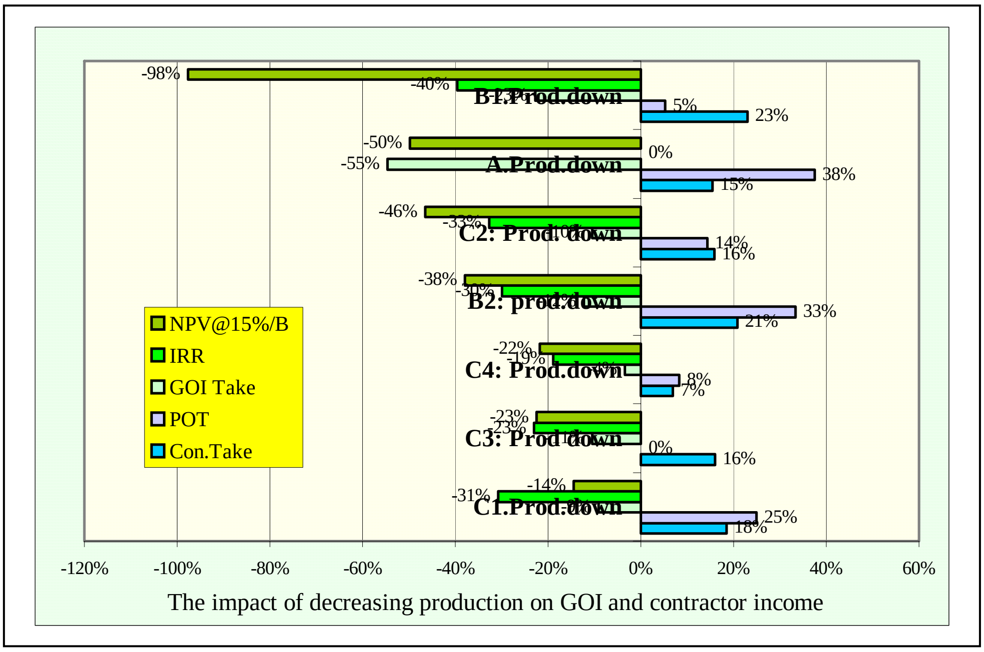


Figure 4.24: Impact of decreasing production

4.2.3. Impact of Tax Consolidation Application in Frontier Areas

4.2.3.1. Single Commercial Contract Analysis Result

To properly characterize the possible outcomes of the six scenarios, the simulations/trials were repeated 10,000 times. The results of the six scenarios are tabulated in Table 4.9 to Table 4.12 and Figures 4.25 to Figure 4.27. The histograms of the base case (65/35 production sharing split with tax consolidation) are presented in Figure 4.28. The histograms for other scenarios had similar shapes but with different values of parameters as described in Tables 4.9 to 4.12. These results then were analysed used the principal agent theory framework as described in section 2.1.1, sub section 2.1.3 and subsection 3.1.

The results show that all six scenarios gave negative mean and median NPV@25%, suggesting that they were not sufficient to pass the commercial performance. Table 4.10 shows that the mean and median of contractor's IRR of 65/35 production split with tax consolidation scenario were around 23% compared to 22% in 55/45 production split without tax consolidation scenario. In comparison, the base case, 65/35 case without tax consolidation, the mean and median of contractor's IRR were around 21%. This result shows that, from the financial aspect of the contractor, the application of tax consolidation was better than the improvement in production split term from 65/35 to 55/45. However, both incentives still could not raise the contractor's IRR to above the minimum required rate of return of high risk investment suggested by Jones's (over 30%).

Also, as is shown in Figure 4.24 and Table 4.11, the application of tax consolidation reduced the values of mean NPV@25% for the GOI to 299 million USD, 313 million, and 327 million from 348 million USD, 361 million and 375 million USD for production sharing split of 55/45, 60/40 and 65/35 respectively. The values of mean GOI's IRR for the cases with tax consolidation were 74.31%, 75.03% and 75.75% for production sharing split of 55/45, 60/40 and 65/35 respectively as were seen Table 4.12. While in without tax consolidation cases, the IRR was undefined since there was no monetary cost for the GOI.

Table 4.9: Summary of contractor's NPV@25% for various scenarios

Statistics	Mean NPV-PSC 55/45		Mean NPV-PSC 60/40		Mean NPV-PSC 65/35	
	Without Taxco	With Taxco	Without Taxco	With Taxco	Without Taxco	With Taxco
Trials	10000	10000	10000	10000	10000	10000
Mean	(50,538,740)	(1,359,937)	(64,003,735)	(15,305,696)	(77,468,730)	(29,251,456)
Median	(60,669,483)	(11,858,765)	(72,099,710)	(23,395,496)	(83,660,081)	(35,234,111)
Mode	---	---	---	---	---	---
Standard Dev.	116,501,988	114,796,296	108,585,282	106,782,784	100,910,526	99,008,895
Variance	13.5E+15	13.1E+15	11.7E+15	11.4E+15	10.2E+15	9.8 E+15
Minimum	(482,983,025)	(431,172,119)	(486,995,875)	(435,414,513)	(491,008,724)	(439,656,908)
Maximum	950,331,015	989,719,243	849,567,083	888,363,590	748,803,152	787,007,937
Range Width	1,433,314,040	1,420,891,362	1,336,562,958	1,323,778,104	1,239,811,876	1,226,664,846

Table 4.10: Summary of contractor's IRR for various scenarios

Statistics	Mean IRR-PSC 55/45		Mean IRR-PSC 60/40		Mean IRR-PSC 65/35	
	Without Taxco	With Taxco	Without Taxco	With Taxco	Without Taxco	With Taxco
Mean	22.32%	24.66%	21.67%	23.96%	20.99%	23.22%
Median	21.98%	24.34%	21.35%	23.66%	20.67%	22.94%
Mode	---	---	---	---	---	---
Standard Dev.	4.79%	5.18%	4.61%	4.99%	4.42%	4.78%
Variance	0.23%	0.27%	0.21%	0.25%	0.20%	0.23%
Minimum	8.08%	9.03%	8.05%	8.98%	8.02%	8.92%
Maximum	49.42%	52.57%	47.82%	50.89%	46.10%	49.08%
Range Width	41.34%	43.54%	39.77%	41.91%	38.09%	40.16%

Table 4.11: Summary of GOI-NPV@25% for various scenarios

Statistics	Mean NPV-GOI 55/45		Mean NPV-GOI 60/40		Mean NPV-GOI 65/35	
	Without Taxco	With Taxco	Without Taxco	With Taxco	Without Taxco	With Taxco
Mean	347,873,613	298,694,809	361,338,608	312,640,569	374,803,603	326,586,329
Median	300,800,584	251,540,362	312,350,179	263,371,074	323,630,334	275,357,240
Mode	---	---	---	---	---	---
Standard Dev.	173,299,025	174,203,574	182,424,296	183,371,855	191,569,350	192,560,157
Variance	30E+15	30.3E+15	33.3E+15	33.6E+15	36.7E+15	37,1E+15
Minimum	109,275,647	54,578,535	108,428,683	53,997,262	107,581,719	53,415,990
Maximum	1,776,562,849	1,737,174,621	1,877,326,780	1,838,530,274	1,978,090,712	1,939,885,926
Range Width	1,667,287,202	1,682,596,086	1,768,898,098	1,784,533,011	1,870,508,993	1,886,469,937

Table 4.12: Summary of GOI-IRR for tax consolidation scenarios

Statistics	IRR-GOI – with Tax Consolidation		
	Split 55/45	Split 60/40	Split 65/35
Mean	74.31%	75.03%	75.75%
Median	71.40%	72.12%	72.85%
Mode	---	---	---
Standard Deviation	16.85%	17.00%	17.20%
Variance	2.84%	2.89%	2.96%
Minimum	39.71%	39.55%	39.38%
Maximum	175.64%	180.73%	176.42%
Range Width	135.93%	141.18%	137.04%

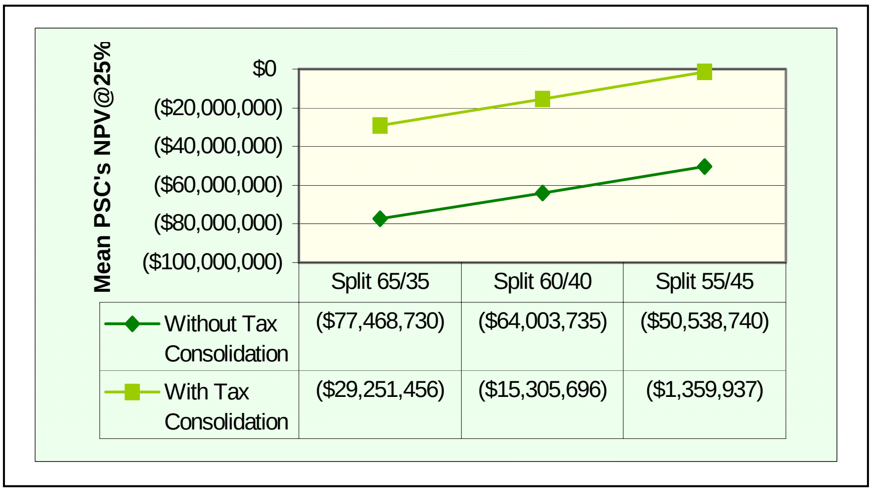


Figure 4.25: Mean NPV@25% of contractor

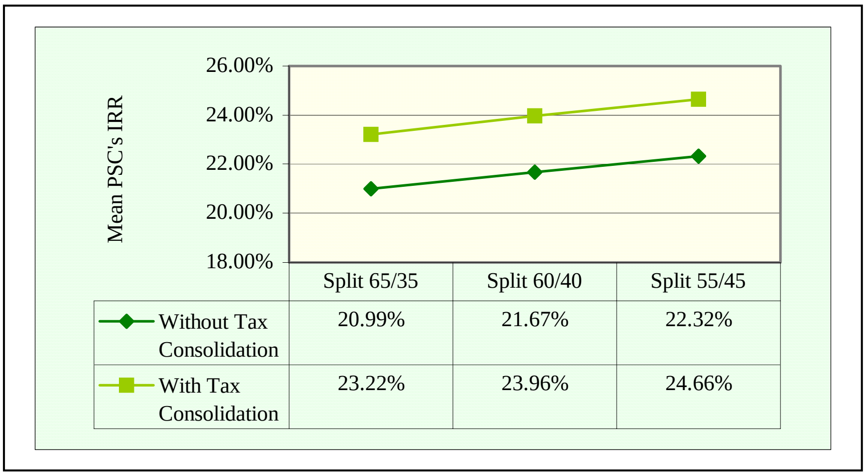


Figure 4.26: Mean IRR of contractor

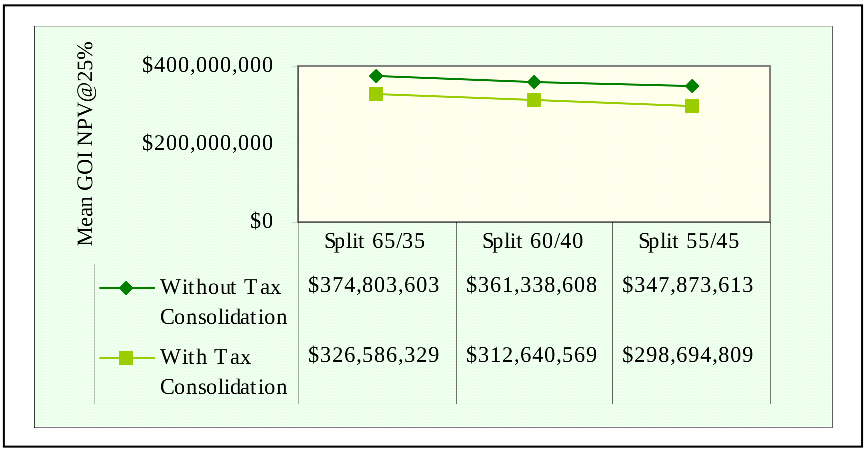


Figure 4.27: Mean NPV@25% of GOI

Compared to the base case, the application of tax consolidation increased contractor's mean NPV@25% by 48 million USD. On the other hand, the improvement of production sharing split of 55/45 without tax consolidation increased contractor's mean NPV25@% by 27 millions USD.

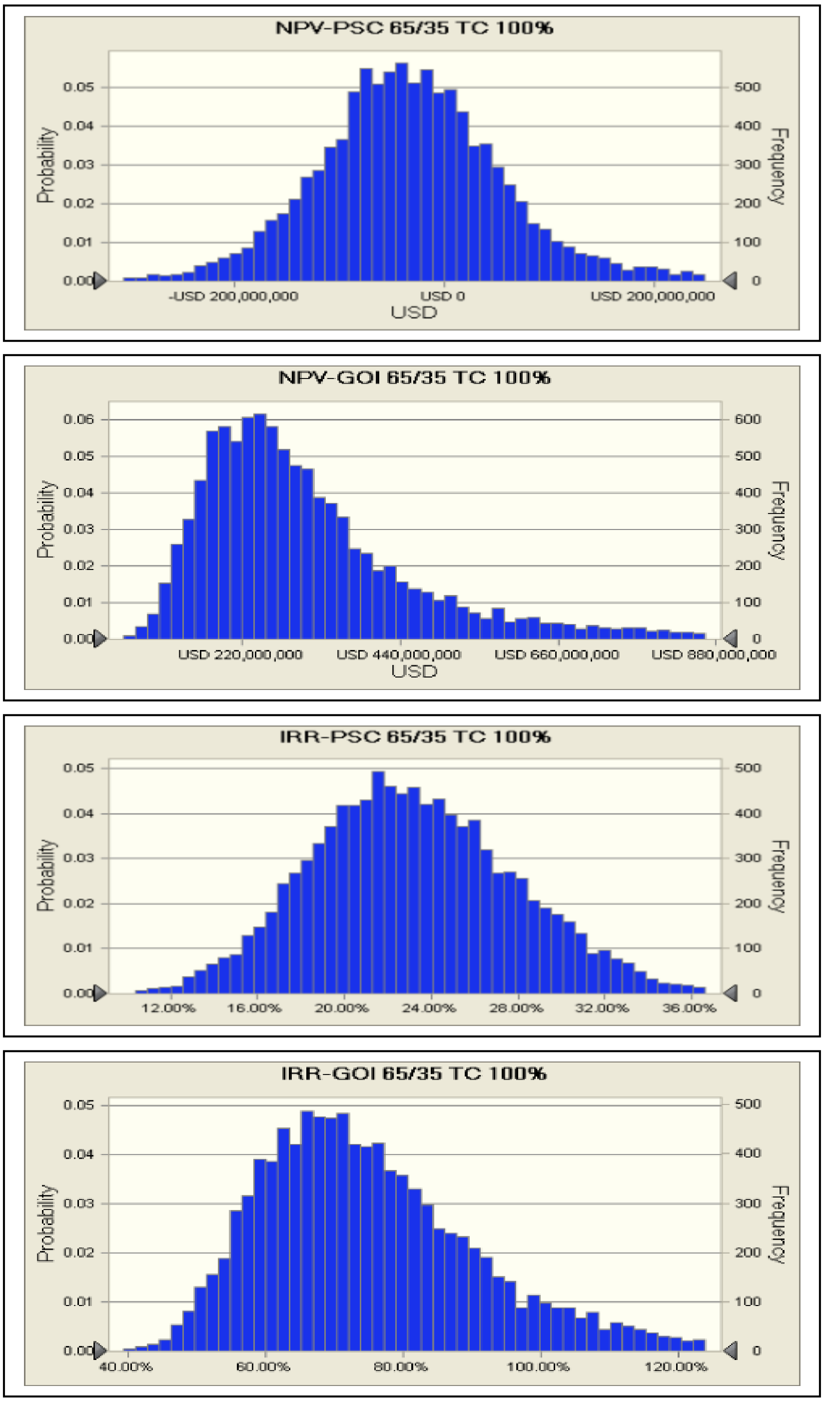


Figure 4.28: Histograms of 65/35 production sharing split with tax consolidation

From the GOI point of view, the application of tax consolidation reduced its mean GOI-NPV@25% by 13% from 375 million USD to 327 million USD in the base case, while the increase in production sharing split reduced it to 347 USD million, a reduction of around 7%. The mean of GOI-IRR in production sharing split 65/35 with tax consolidation case is 75.75%, a good and healthy value. However, this also meant some financial risk to the government, considering the fact that in the production split scenario, the GOI-IRR was undefined; there was no financial risk to the GOI.

Table 4.13 and Figure 4.29 show probability distribution of the ratio of (Net Cash Flow/Exploration Cost) of the base case, 65/35 production sharing split with tax consolidation, and 55/45 production sharing split without tax consolidation to the base case (Net Cash Flow/Exploration Cost) from the Monte Carlo simulation. Naturally, the ratio for the base case was 1, while the ratio values of 65/35 production sharing split with tax consolidation, and 55/45 production sharing split without tax consolidation were 1.63 and 1.17 respectively. This suggests that the application of tax consolidation will potentially give contractor 1.63 times more net cash flow for each dollar spent in exploration, on the other hand improvement in production sharing split to 55/45 will increase it by only 1.2 times. Direct comparison between the two cases also shows that tax consolidation case will potentially gave almost 1.4 times as much as the case with production sharing split increase for each dollar spent in exploration. This value would be used to approximate the number of contracts signed in the aggregate contract analysis mentioned in the next section.

With the assumptions as described above, on the basis of single commercial contract, the results suggest that from the point of view of contractor, tax consolidation application was more attractive incentive than progressive improvement in production sharing split from 65/35 to 55/45. Hence, it was more likely to increase the level of exploration investment. However, it came with more penalties, and more importantly, the tax consolidation application came with more risk to the GOI than the increasing production sharing split scenario.

Table 4.13: The ratio contractor's NPV@25% to its exploration cost

Statistics	Split 65/35	Split 65/35 with Taxconso	Split 5545
Trials	10,000	10,000	10,000
Mean	1.00	1.63	1.17
Median	1.00	1.63	1.17
Mode	1.00	---	---
Standard Deviation	0.00	0.02	0.02
Variance	0.00	0.00	0.00
Minimum	1.00	1.54	1.04
Maximum	1.00	1.75	1.23
Range Width	0.00	0.21	0.19

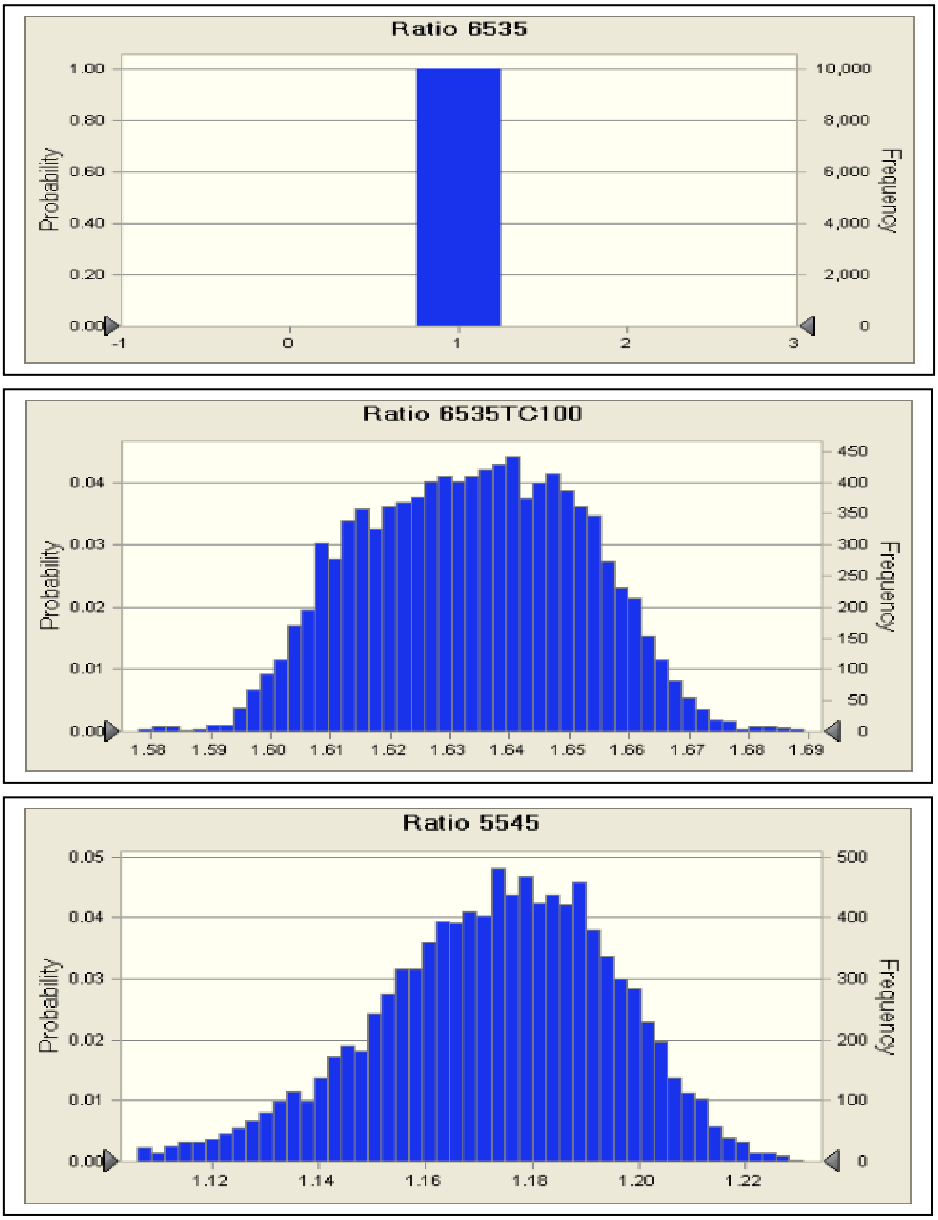


Figure 4.29: Histograms of ratio contractor's net cash flow to its exploration cost for tax consolidation scenarios

4.2.3.2. Aggregate Combined Contracts Analysis Result

The analysis in the previous section shows that tax consolidation can potentially be more attractive incentive to the contractor than progressive improvement in production sharing split to increase the level of E&P investment in Indonesia. However, it came at a price to the government, as it posed risk and reduced the NPV and cash flow share of GOI in a single contract basis. To assess whether the increase in exploration investment (thus more contracts signed) will eventually generate more aggregate NPV for the government, analysis on the aggregate level was performed by Monte Carlo simulation.

As mentioned in Chapter 3, the aggregate combined contract analysis will be limited to only the additional areas signed during the first 10 years since tax consolidation (production sharing split 65/35 with tax consolidation) application or increase in production sharing split to 55/45 starts to be effective. While the number of contracts signed each year under tax consolidation scenario was assumed to have triangular probability distribution with,

a) Tax consolidation case (production sharing split 65/35 with tax consolidation): most likely of 3 and minimum and maximum values of 0 and 6 respectively.
b) Progressive improved production split case (production sharing split 55/45 without tax consolidation): most likely value of 2 and minimum and maximum values of 0 and 4 respectively.

The most likely value of 3 and 2 in cases a) and b) respectively were obtained based on the ratio of (Net Cash Flow/Exploration Cost) of the respective cases. As mentioned in the previous section, the ratio between the two cases from the single contract analysis was found to be around 1.4. This ratio was then used to approximate the ratio of likelihood of the number of contracts between the 2 cases (3 and 2, or ratio of 1.5).

The simulation results after 10,000 trials are presented in Tables 4.14 to Table 4.15. The results show that, under the assumption of the number of additional contracts mentioned above, tax consolidation application can potentially add more than 700 million STB of reserve, almost doubling the potential reserve addition from production split increase scenario (425 millions STB). However, the mean GOI IRR was only around 22%, less than the minimum required rate of return high-risk investment as suggested by Jones (30%). Consequently the mean and median of GOI NPV@25% were negative (minus 35 millions USD and minus 108 millions USD respectively. In contrast, in the production split improvement case, the mean and the median GOI NPV@25% were USD 252 and USD 185 millions respectively.

Table 4.14: Aggregate Monte Carlo simulation summary for tax consolidation scenario

Statistics	Reserve	NPV-GOI	IRR-GOI	NPV-PSC	IRR-PSC
Mean	716,338,520	(34,824,952)	22.23%	(613,898,134)	10.33%
Median	665,356,438	(108,612,062)	21.89%	(609,571,664)	10.70%
Mode	0	0			
Standard Deviation	430,322,113	363,026,952	11.16%	170,609,668	5.49%
Variance	2.E+17	1.E+17	1.25%	3.E+16	0.30%
Minimum	0	(743,367,579)	-6.25%	(1,693,400,920)	-9.90%
Maximum	2,756,223,012	2,661,762,388	84.93%	390,092,512	31.14%
Range Width	2,756,223,012	3,405,129,966	91.18%	2,083,493,431	41.04%

Table 4.15: Aggregate Monte Carlo simulation summary for production sharing split increase scenario

Statistics	Reserve	NPV-GOI	NPV-PSC	IRR-PSC
Mean	426,604,047	252,004,050	(644,331,019)	7.92%
Median	372,586,054	184,733,801	(644,746,388)	8.07%
Mode	0	0		
Standard Deviation	332,825,229	260,633,272	169,762,552	5.84%
Variance	1.11.E+17	6.78.E+16	2.88.E+16	0.34%
Minimum	0	0	(1,487,165,140)	-12.40%
Maximum	2,381,082,061	2,573,900,429	289,158,210	29.47%
Range Width	2,381,082,061	2,573,900,429	1,776,323,349	41.88%

Figures 4.30 to 4.32 show the histograms and the cumulative distributions of the GOI's NPV@25% and IRR. They show that in tax consolidation case, the

probability of the GOI’s NPV@25% lower than zero or equivalently the probability of the IRR to be lower than 25% was around 60%. This suggests that application of tax consolidation was a high-risk decision for the GOI

From contractor’s views, the mean aggregate of NPV@25% in both tax consolidation and production split improvement scenarios were negative, while the mean aggregate IRR were 10.3% and 7.9% respectively. These suggest that the tax consolidation application could increase the contractor’s IRR, but the values still below the low risk investment that proposed by Jones. Moreover, the contractor’s IRR as an aggregate was relatively low, even with tax consolidation applied, indicating that the investment was not very attractive.

It can be concluded that under the assumptions used in this study and the results were analysed used principal agent theory framework, the application of tax consolidation poses high risk to the GOI, therefore was not likely to be beneficial to GOI. While on the view of contractor, although tax consolidation application as incentive resulted better than increasing production split in single commercial contract analysis, but the IRR still below the low risk investment proposed by Jones and as an aggregate its value was relatively low, therefore this incentive was not sufficient to attract investment.

The result of this study was different than the result of IPA study. Though in IPA study the number of trials was limited to only 10, the result seemed to suggest that the application of tax consolidation would have positive impact on GOI income. The difference in the conclusions of this study and IPA study can be attributed to the different assumption used, especially in the costs incurred (exploration, development and operating expenditures). The assumed costs used in this study were much more expensive than the ones used in IPA study. Under the significantly more stringent costs, more capitals was needed for exploration and development; hence much higher portion of the revenues were used to recover the cost, and less would be available to be shared between both parties. We think that the assumptions used in current study was more up to date than the assumptions used in IPA study, hence the result is more representative and relevant to current situation.

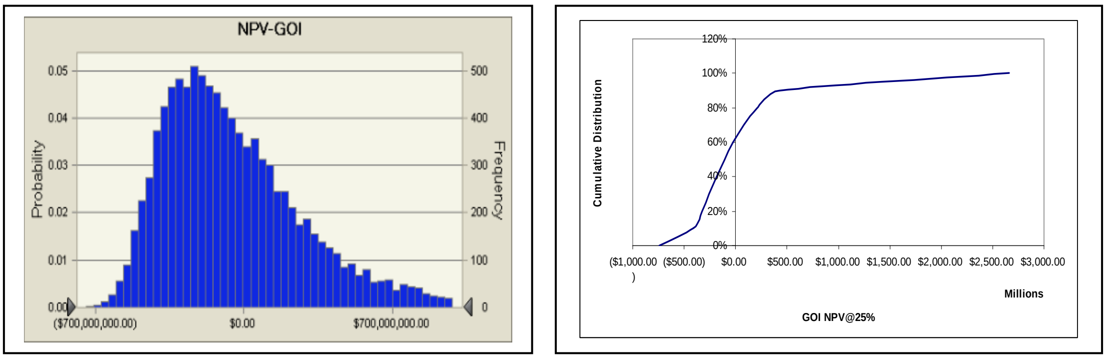


Figure 4.30: Histogram and cumulative distribution of GOI's NPV@25% of tax consolidation scenario

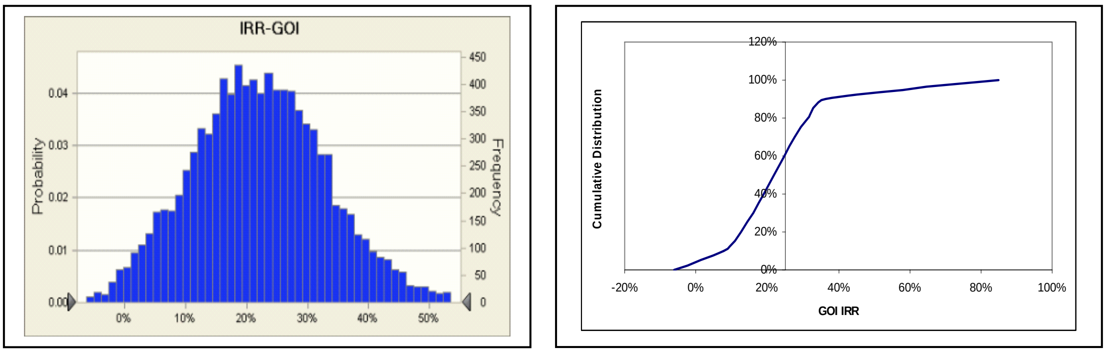


Figure 4.31: Histogram and cumulative distribution of GOI's IRR of tax consolidation scenario

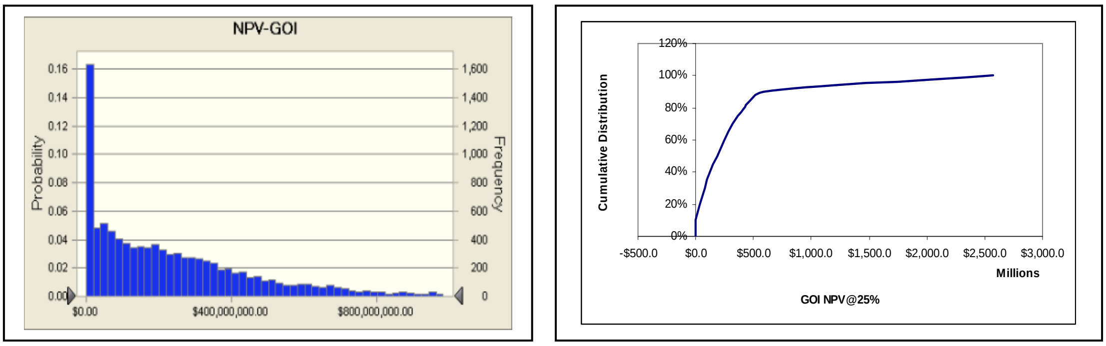


Figure 4.32: Histogram and cumulative distribution of GOI's NPV@25% of production sharing split improvement case scenario

Under the assumptions described in the study, following conclusions are reached:

1) From contractor's financial aspect, tax consolidation was more attractive incentive compared to increase in production sharing split. It did not only give higher NPV@25% but also reduced the exploration risk.
2) Tax consolidation was less attractive to the GOI, not only it reduced GOI's NPV@25% but it also posed financial risk to the GOI.
3) The application of tax consolidation at the aggregate level posed high risk to the GOI; hence, unless, the potential additional reserves and potential effects to local economy development outweighed the risk, the application of tax consolidation is not likely to be beneficial.

4.3. The Most Desirable Contract System for Indonesia on the view of Petroleum Company

The Analytic Hierarchy Process (AHP) in the benefit-cost-risk framework analysis in this study was designed to understand the companies' views with respect to the most desirable fiscal terms for petroleum E&P venture in Indonesia, given current Indonesia's geological petroleum resource potential, economic, social and political conditions. Three alternative fiscal systems have been selected, namely the Modern Royalty and Tax (RAT), Risk Service Contract (RSC) and the existing PSC system. The theoretical and methodology framework foundations, model and assumptions used in this analysis and respondents' profile are presented in Chapter 2 sub section 2.3.2, Chapter 3 sub section 3.3 and Chapter 4 sub section 4.2.1. The respondent's judgment, opinion and pair wise comparisons between criteria and alternatives of petroleum contracts were collected through the same respondents and questionnaires as mentioned in sub section 3.2.1.1 and Appendix A.

As already mentioned earlier, the questionnaires were sent to 24 petroleum companies presently active in petroleum E&P operation in Indonesia and five petroleum experts during 1st of March to 31st of August 2004. Besides two experts, eight (30% of total 24 companies) companies returned the questionnaires, and these eight had in total of 45 petroleum contracts in Indonesia. For more details, the profile of respondents' can be seen in section 4.2.1. The results of the questionnaires were processed with Expert Choice 2000 second edition software from Expert Choice, Pittsburgh PA. First for the benefit hierarchy structure, then the cost hierarchy and finally followed by risk hierarchy structure. The weighting of benefit, cost and risk criteria for rating the vector of *Benefits / (Costs x Risks)* were calculated through the comparison of the mean score of combinations of the benefit criteria, cost criteria and the risk criteria. The rating vector of *Benefits / (Costs x Risks)* was used to weight the corresponding vectors of priorities among the alternatives and to obtain the overall ranking of the alternatives. The highest score of alternative contract system was the most desired contract system on the petroleum companies' views.

Figure 4.33 shows that the combination of all benefit criteria R, CP, TRA and R/P was given an overall mean score of 5.4 by companies' respondents and of 5.6 by contracts' respondents, it is suggested that on the view of entire respondents the geological potential gave over strong/important plus to very strong/important impact for the size of benefit stream in investing money in a petroleum business in Indonesia.

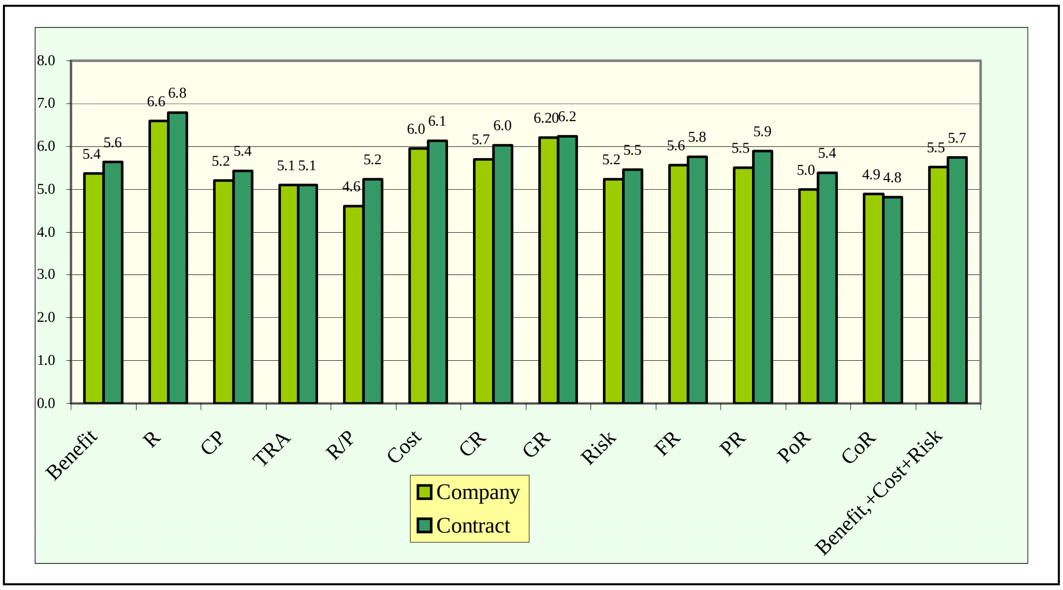


Figure 4.33: Mean Score of Benefit, Cost and Risk Criteria

In the cost hierarchy structure, as a whole those two cost criteria were valued and resulted in mean score of 6.0 by companies' respondents and of 6.1 by contracts' respondents. It is suggested that on the view of the entire respondents the costs on doing petroleum E&P business in Indonesia were very costly.

The four risk criteria had an overall mean score of 5.2 on the companies' respondents, and on the view of contracts' respondents those four risk criteria had an overall mean score slightly over the score of companies' respondents with mean score of 5.5. It is suggested that the risks criteria in Indonesia valued were also very important variables in increasing the cost and reducing the revenues but slightly below the costs criteria.

All of these mean scores mentioned above also show that the cost criteria got the highest score, it indicated that the cost in doing petroleum E&P business gave the highest impact in reducing revenues on the petroleum E&P operation in Indonesia. As a whole combination of the benefit, cost and risk criteria got mean score of 5.5 by companies' respondents and 5.7 by contracts' respondents. These facts indicated the entire criteria gave very strong impact on doing petroleum E&P business in Indonesia.

From these score, we got the weighting score of combination of benefit criteria: combination of cost criteria: combination of risk criteria as follows. On the view of companies' respondents we got of 5.4 : 6.0 : 5.2 = 1.1 : 1.2 : 1.0 that can be rounded into 1 : 1 : 1. While on the view of contracts' respondent we got = 1.0 : 1.1 : 1.0 that can also be rounded into 1 : 1 : 1. It can be concluded that the benefit, the cost and the risk criteria had a similar weighting. This weighting was used in the calculation of the rating vector of *Benefits / (Costs x Risks)* as mentioned earlier.

Perceptions, feelings, judgments and memories require both knowledge and experiences about the subjects. Different in knowledge and experiences may result in different perception, feeling, judgment and memories about them. Different location work area and different production profile may result different experiences and resulted in different in perception, judgment and memories about the petroleum operations. Subsequently, the analysis had been performed on the basis of the size of respondents' production profile and the operating location. The petroleum company had production rate less than 10 MBOEPD called the *small company*, while had production rate between 10 - 50 MBOEPD called the *medium company* and petroleum company had production rate over 50 MBOEPD called *large company*.

The result and finding of this AHP analysis in the benefit cost risk framework are presented below.

4.3.1. The Most Desirable Contract System on the View of *Small Company* operated in Eastern-part of Indonesia

There were a total of 91 petroleum contracts operated in the eastern part of Indonesia during 1966 – 2003, eight contracts of which were producing, 30 contracts were in the exploration phase and 53 contracts had been terminated. Of the eight producing contracts, five were in the form of PSC, two were the TAC contracts and one was JOB contract. There was one company with production less than 10 MBOPD returned the AHP questionnaire. This company had three PSC contracts and all were located onshore area in the eastern-part of Indonesia. The respondent was contributing 38% of total producing contract, 60% of producing PSC, or 8% of active contracts in the eastern-part of Indonesia, thereby could be considered as a representative sample of *small company* operates in the eastern-part of Indonesia.

In determining the benefit hierarchy, the scope of analysis was used to determine which criteria and what impact does each criterion have on the benefits stream. The benefit criteria were the Reserves (R), Total Reserves Addition in the last 5 years (TRA), Current Production (CP) and Reserve/Production Ratio (R/P) of a field, basin or country.

The result shows that in the eye of *small company* all the four criteria would impact substantially the benefit stream. With the score of 7, CP gave the greatest benefit; followed by R/P (score 5), R and TRA, the last two have the same score of 4 (Table 4.16). This was consistent with the fact that *small company* nature in focusing on current production, due to needed a steady cash income from its production. Moreover the productivity of petroleum E&P activities in eastern-part of Indonesia had been only 2% of total producing contracts or 14% of total the producing PSC contracts.

Table 4.16: Score of benefit, cost and risk criteria according to the *small company*

1	**Benefits**	
	- Current Production (CP)	7
	- Reserves/Production Ratio (R/P)	5
	- Reserves Potential (R)	4
	- Total Reserves Addition (TRA)	4
2	**Cost**	
	- Geological Risk (GR)	6
	- Cost Risk (CR)	5
3	**Risk**	
	- Price Risk (PR)	7
	- Fiscal Risk (FR)	7
	- Contract Risk (CoR)	5
	- Political Risk (PoR)	5

Using the Expert Choice software, we have computed the paired comparisons of all four benefits criteria and the results are presented in Table 4.17. The results show that with overall inconsistency index of 0.00, PSC had the highest score (0.541), followed by RAT (0.412) and RSC (0.048).

Table 4.17: Result of AHP: the view of the *small company*

Alternatives	**Benefit**	**Cost**	**Risk**	**Cost x Risk**	**Benefit/(Cost x Risk)**	**Rank**
PSC	0.541	0.627	0.361	0.226	2.390	2
RAT	0.412	0.261	0.203	0.053	7.776	1
RSC	0.048	0.112	0.437	0.049	0.981	3

Sensitivity 1: inconsistency index of benefit/CP was decreased from 0.28 to 0.05

Alternatives	**Benefit**	**Cost**	**Risk**	**Cost x Risk**	**Benefit/(Cost x Risk)**	**Rank**
PSC	0.462	0.627	0.361	0.226	2.041	2
RAT	0.488	0.261	0.203	0.053	9.211	1
RSC	0.05	0.112	0.437	0.049	1.022	3

Sensitivity 2: inconsistency index cost/CR was decreased from 0.28 to 0.00

Alternatives	**Benefit**	**Cost**	**Risk**	**Cost x Risk**	**Benefit/(Cost x Risk)**	**Rank**
PSC	0.541	0.517	0.361	0.187	2.899	2
RAT	0.412	0.371	0.203	0.075	5.471	1
RSC	0.048	0.112	0.437	0.049	0.981	3

With respect to the cost hierarchy, criteria that gave negative impacts, as they tend to increase the cost were Geological Risk (GR) and Cost Risk (CR). From the *small production* company perspective, with the score of 6 (very strong) the GR was more costly, as compared to CR (score 5 = strong plus).

In summary, the result of AHP analysis on cost hierarchy structure was quite similar with the benefit hierarchy structure, in which PSC had the highest and significant score (0.627) as compared to RAT (0.261) and RSC (0.112), on the view *small company*. The overall inconsistency index in cost hierarchy was relatively high (0.28) but in the range could be tolerated.

In addition to benefit and cost hierarchy analyses, we had also performed the risk hierarchy analysis. The four criteria considered were Price Risk (PR), Fiscal Risk (FR), Contract Risk (CoR) and Political Risk (PoR). With the score of 7 (extremely significant), the Price Risk (PR) and Fiscal Risk (FR) were found to be the two most important parameters with respect to risk, followed by Contract Risk (CoR) and Political Risk (Score 5 = strong plus). The result of AHP analysis of risk hierarchy structure shows that with overall inconsistency index 0.00, RSC (0.437) had the highest score follows by PSC (0.361) and then RAT (0.203).

As already calculated earlier, the benefit, the cost and the risk criteria had a similar weighting. With this similar weighting, then we computed for each alternative the ratio of Benefit to Cost times the Risk. As shown in Table 4.17, the results show that RAT had the highest score of 7.776, followed by the PSC (2.390) and RSC (0.981). While it had the highest score in the benefit hierarchy structure analysis and was ranked as the first choice, the PSC had also the highest score in cost hierarchy and risk hierarchy. The end result was the PSC had a lower score as compared to the RAT system.

To test the sensitivity of the results, two analyses were made involving changes of two parameters, named the CP and CR; both were aimed at reducing inconsistency index. The sample change in CP and CR would reduce the inconsistency index of Benefit/CP and Cost/CR, respectively, from 0.28 to 0.05 and from 0.28 to 0.0, while keeping the other parameters constant. The two sensitivity analyses show that the RAT was still the most desirable alternative as compared to RAT and RSC (Table 4.17 and Figure 4.34).

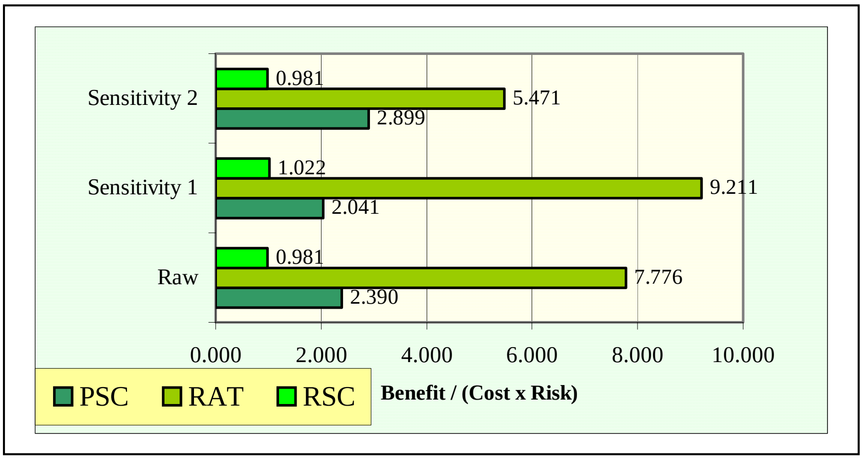


Figure 4.34: Result of AHP: the view of *small* company

From the hierarchy structure analysis above, we can conclude that on the *small company* view's, given Indonesia's current condition, RAT system was the most desirable fiscal system. It was followed by the PSC and RSC system. The result of this analysis was consistent with the respondent's statement by giving the answer *no* when asked on an open question: *Is PSC still acceptable in attracting investor in Indonesia.*

4.3.2. The Most Desirable Contract System on the View of *Medium Company* operates in Western part of Indonesia

Similar with situation in the eastern part of Indonesia, only one company having production between 10 and 50 MBOPD had completed and returned the questionnaires. This respondent had six PSC and one TAC contracts; all these contracts were operated in the western part of Indonesia some in onshore and some in offshore location. The respondent represented 14% of producing contracts or 5% of total contracts operated in the western part of Indonesia.

As shown in Table 4.18, the result of benefit hierarchy structure analysis shows that with the score of 7, the R criteria gave the highest impact on the benefit stream, it was followed by the CP and R/P (each score of 5), and TRA (score of 2). This result deviated from the previous finding involving *small company* view. The *small company* considered the CP would be the criteria that gave the most important impact on benefit stream. Nonetheless, as shown in Table 4.19 the result of paired comparison suggested with overall inconsistency index 0.13, RAT (0.485) had the highest score; it was followed by PSC (0.329) and then RSC (0.187).

Table 4.18 shows that in the cost hierarchy structure analysis, the result of analysis for *medium company* was consistent with that of small company, i.e. the GR was more costly parameter (score 6 = very strong) as compared to CR (score 5 = strong plus). Also, the computed AHP on cost hierarchy structure shows with overall inconsistency index 0.00, the PSC had the highest score (0.503) and was followed by RAT (0.260) and RSC (0.237) (see Table 4.19).

Table 4.18: Score of benefit, cost and risk criteria according to *medium company*

1	**Benefits**	
	- Reserves Potential (R)	7
	- Current Production (CP)	5
	- Reserves/Production Ratio (R/P)	5
	- Total Reserves Addition (TRA)	2
2	**Cost**	
	- Geological Risk (GR)	6
	- Cost Risk (CR)	5
3	**Risk**	
	- Fiscal Risk (FR)	7
	- Price Risk (PR)	4
	- Contract Risk (CoR)	3
	- Political Risk (PoR)	2

In risk hierarchy analysis, the result of questionnaires indicated that the Fiscal Risk was extremely significant factors (score 7), was followed by Price Risk (score 4), Contract Risk (score 3) and Political Risk (score 2). The AHP analysis on risk hierarchy structure (Table 4.19) shows that with overall consistency index 0.00, PSC had the highest score (0.407) and was followed by RSC (0.375) and RAT (0.216).

In terms of ratio of Benefit to Cost times Risk, with similar weighting of combination of benefit cost and risk criteria above, the computed results for each alternative (Table 4.19) shows that RAT had the highest score of 8.636, it was followed by the RSC (2.104) and PSC (1.607). The sensitivity analysis also provided similar conclusions. Like the previous finding, the overall results involving *medium company* view, given current condition, the RAT was the most desirable choice of contract system for Indonesia compared to PSC and RSC (Figure 4.35).

Table 4.19: Result of AHP: the view of *medium company*

Alternatives	Benefit	Cost	Risk	Cost x Risk	Benefit/(Cost x Risk)	Rank
PSC	0.329	0.503	0.407	0.205	1.607	3
RAT	0.485	0.260	0.216	0.056	8.636	1
RSC	0.187	0.237	0.375	0.089	2.104	2

Sensitivity 1: inconsistency index of benefit/CP is decreased from 0.69 to 0.00

Alternatives	Benefit	Cost	Risk	Cost x Risk	Benefit/(Cost x Risk)	Rank
PSC	0.239	0.503	0.407	0.205	1.167	3
RAT	0.472	0.260	0.216	0.056	8.405	1
RSC	0.289	0.237	0.375	0.089	3.252	2

Sensitivity 2: inconsistency index cost/GR is decreased from 0.83 to 0.03

Alternatives	Benefit	Cost	Risk	Cost x Risk	Benefit/(Cost x Risk)	Rank
PSC	0.329	0.631	0.407	0.257	1.281	3
RAT	0.485	0.179	0.216	0.039	12.544	1
RSC	0.187	0.19	0.375	0.071	2.625	2

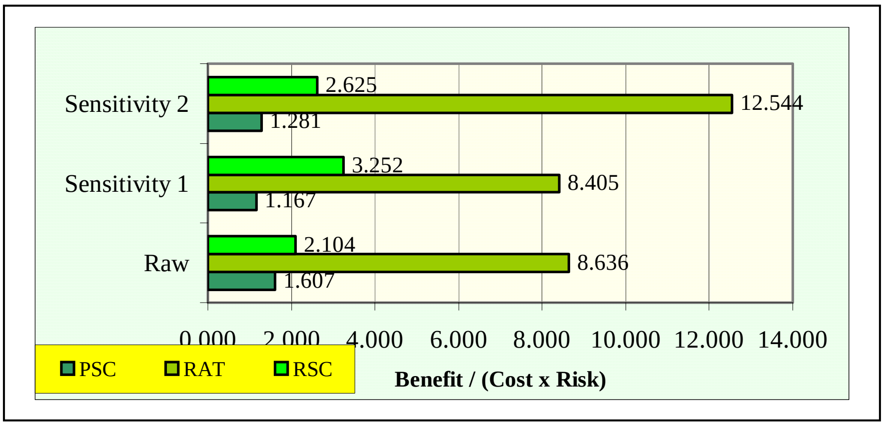


Figure 4.35: Result of AHP: the view of *medium company*

4.3.3. The Most Desirable Contract System on the View of *Large Company*

There were five companies having production over 50 MBOPD responded to the questionnaires. However, only one company answered the question about AHP completely and consistently, so this company was taken as sample for the AHP analysis. The company had nine PSC contracts, representing about 27% of the 32 producing PSC contracts. All nine contracts operated in offshore area, some in western and some in eastern-part of Indonesia and had been operating more than 33 years in Indonesia.

Table 4.20 shows R was the extreme significant criteria, had the highest score of 7, followed by CP (score 6, TRA (score 5) and R/P (score 4). The result of paired comparison of all the four benefit criteria is presented in Table 4.21, showing that with overall inconsistency index 0.00, the PSC was the most preferable contract system (score of 0.493), it was followed by RSC (0.304) and then RSC (0.205).

Table 4.20: Score of benefit, cost and risk criteria according to *large company*

1	**Benefits**	
	- Reserves Potential (R)	7
	- Current Production (CP)	6
	- Total Reserves Addition (TRA)	5
	- Reserves/Production Ratio (R/P)	4
2	**Cost**	
	- Cost Risk (CR)	7
	- Geological Risk (GR)	6
3	**Risk**	
	- Price Risk (PR)	7
	- Political Risk (PoR)	6
	- Fiscal Risk (FR)	5
	- Contract Risk (CoR)	4

Contrary to the two previous findings involving small and medium company views, the *large company* views gave the score of 7 to the CR, it was an extremely significant factor as compared to GR (score of 6 = very strong significant). This was consistent with their better knowledge in the geology of the area, given their years of operation (over 33 years) in the area (Western-part of Indonesia). Subsequently, the result of AHP analysis on cost hierarchy structure (Table 4.21) shows that with overall inconsistency index 0.02, the RSC had the highest score (0.461), and then was followed by PSC (0.442) and RAT (0.097).

In terms of risk, the PR (score 7) occupied the highest in the risk hierarchy structure, followed by PoR (score 6), FR (score 5) and CoR. The result seemed to be consistent with their years of operating experiences in the area. Subsequently, the *large company* in the western part of Indonesia view that with overall inconsistency index 0.01, the PSC had the highest score (score = 0.528) in hierarchy structure, then was followed by RSC (0.322), and then RAT (0.149).

The computed result of ratio of Benefit to Cost times Risk for each alternative as presented in Table 4.21 and Figure 4.36 show that RAT (14.184) was the most desirable choice and it was followed by PSC (2.112) and then RSC (2.048). Note that the sensitivity analysis also shows similar conclusions.

Table 4.21: Result of AHP: the view of *large company*

Alternatives	Benefit	Cost	Risk	Cost x Risk	Benefit/(Cost x Risk)	Rank
PSC	0.493	0.442	0.528	0.233	2.112	2
RAT	0.205	0.097	0.149	0.014	14.184	1
RSC	0.304	0.461	0.322	0.148	2.048	3

Sensitivity: inconsistency index cost/GR is decreased from 0.02 to 0.00

Alternatives	Benefit	Cost	Risk	Cost x Risk	Benefit/(Cost x Risk)	Rank
PSC	0.493	0.418	0.528	0.221	2.234	2
RAT	0.205	0.099	0.149	0.015	13.897	1
RSC	0.304	0.484	0.322	0.156	1.951	3

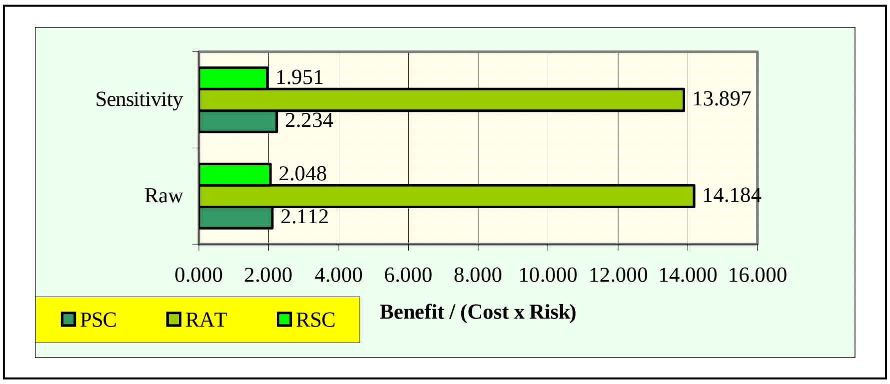


Figure 4.36: Result of AHP: the view of *large company*

The *medium company* and *large company* provided different answers between the result of the AHP analysis and their answers to the open question (in questionaire) "*whether or not the PSC is still acceptable in attracting investor in Indonesia*".

The values of *Benefit / (Cost x Risk)* of RAT system were much higher than other two systems and this values still consistent much higher after sensitivity analysis were done. Moreover the AHP has been developed based on some fundamental facts and thoughts that human mind is inconsistent but knowledgeable people will have a rationale mind and can value two different objects comparatively. Given that all of the steps have been taken, while all decision criteria have also been evaluated and scored, followed by paired comparisons based on the view of CEO's petroleum company who has expertise and experiences with this subjects, the present result of AHP analysis should be more reliable as compared to the answer of the open question only.

In brief, the result found that the respondents' opinions and judgment were consistent with the respondents' experiences. Consistent with the fact that *small company* focus on current production, due to he/she needed a steady cash-in come from its production, in evaluating the benefit parameters, the *small company* placed the current production as the most significant factor in impacting the benefit stream. Similarity *medium company* and *large company*, consistent with their better knowledge in the geology of the area, given their long years of operation (over 33 years) in western-part of Indonesia, they considered the reserves potential was the most significant factor. If only benefits parameter were considered in decision-making, *small company* and *large company* considered the PSC was the most desirable choice of contract, while the *medium company* preferred to choose the RAT.

Moreover in the cost hierarchy structure analysis, *small company* and *medium company* considered that the geological risk was the most costly parameter; while the *large company* view the cost risk was more important parameter in decision process. This was consistent with the fact that given the years of operating experiences, the geological risk in the western part of Indonesia area had been very well assessed, while with limited budget the *small company* and *medium company* operating in the eastern part of Indonesia had to be more selective in developing the exploration prospects.

In the risk hierarchy analysis, *small company* and *large company* views placed the price risk above the fiscal risk, while the contract risk and political risk were considered to have less impact. In contrast the *medium company* view placed fiscal risk (score 7) far above price risk (score 4), while the contract risk and political risk were considered to have less impact.

It can be concluded, the benefit cost risk analysis involving AHP could be used in identifying the most desirable petroleum contract system of petroleum E&P venture, and given recent Indonesia's geological potential, economics, social and political condition, all respondents seemed to choose the Modern Concessionary or Royalty and Tax (RAT) system as the most desirable petroleum contract system for Indonesia compared to the existing Production Sharing Contract (PSC) and Risk Service Contract (RSC).

4.4. Investment Climate of the Petroleum Business in Indonesia

As already noted in section 4.2.1.1 about respondent's profile, there was eight (30%) companies returned the questionnaires, and these eight respondents had a total 45 petroleum contracts in Indonesia, they were of 37% of the total active contracts and 122% of the total producing contracts. Each respondent hold varies number of contracts from two to as high as 13 contracts. Of the total 45 contracts, there were 37 PSC, 4 JOB, 1 JOA and 3 TAC contracts. In addition, of the five retired executives two returned the questionnaires. Two analyses were drawn, first were analysed based on the view of company respondent and second were analysed based on the view of contract respondent used some principles of petroleum contract as shown on sub section 2.1.3 and sub section 3.4. The result and finding are presented as follows.

4.4.1. Investment Decision Variables

Any decision would have several favourable or positive impact, unfavourable or negative impact and uncertain concerns to consider. The favourable impacts were called the *benefits* and the unfavourable impacts were called the *costs*. The uncertain concern of a decision was the negative *risks* that can entail. The cost was the uncertain/the negative impact would entail immediately and the risk was the negative impact that will be entailed in the future.

As already mentioned earlier, the benefits that might be obtained when an investor invests in E&P venture in Indonesia could be realised from its geological potential, involving the reserves potential (R), total reserves addition in the last several years (TRA), current production (CP) and reserve/production ratio (R/P) of a field/basin/country. The benefit criteria above were scored based on the strength of their impact on the size of benefit stream that might be obtained, if a petroleum company would like to invest in petroleum E&P venture in Indonesia, with assumption that the four criteria above were current Indonesia's conditions. The score was set up from 1 to the highest of 7. The mean score of benefit, cost and risk criteria could be seen in Figure 4.33 above.

Around 80% of the company's respondents gave score 7 of (most important) on Reserve Potential criteria in evaluating the benefit stream, while the remaining 20% gave score 6 and below, then resulted an average score of 6.6 (see Figure 4.33 above). While analysed based on contract's respondents gave slightly above that figure an average score of 6.8, in which 91% of contract's respondents gave score 7 on reserves potential, and the remaining 6% gave score 4 and 2% gave score 6. Based on the results, all respondents valued the Reserve Potential was considered as the most important variable in evaluating the size of benefit stream in investing in a petroleum business in Indonesia.

The second important variable was the current production (CP), with an average score of 5.2, in which 90% of the company's respondents gave score 5 (strong/important plus) and over to CP. While on the view of contract's respondents, CP had an average score slightly over of 5.4, in which 94% of contract's respondents gave score 5 and over to CP. Based on the results, all respondents agreed the CP was considered as the strong/important plus variable in evaluating the benefit stream.

The next important variable was the total reserves addition (TRA) with mean score of 5.1 (strong/important plus), in which 70% of the company's respondents gave score of 5 (strong/important plus). The TRA got similar mean score of 5.1 from the view of contract's respondents. It was followed by reserves/production ratio (R/P) parameter, which valued by the company's respondents mean score of 4.6, while the contract's respondents gave slightly higher score of 5.2 (strong/important plus).

The combination of all benefit variables R, CP, TRA and R/P was given an overall average score of 5.4 by company's respondents and 5.6 by contract's respondents, suggesting that on the view of entire respondents the geological potential was considered as over strong/important plus to very strong/important variable in evaluating the size of benefit stream in investing money in a petroleum business in Indonesia.

When respondents were asked, which one was the most costly between geological risk and cost risk criteria in evaluating the size of cost of petroleum E&P investment in Indonesia, the company's respondents scored an overall mean of 6 (very strong), in which the geological risk was slightly more costly compared to cost risk with an overall mean score of 6.20. The contract's respondents valued geological risk slightly over an average score of 6.23, which means it was slightly above very strong impact in evaluating the size of cost of petroleum E&P activity in Indonesia. Moreover, 40% of company's respondents gave the geological risk a score of 7 (the most costly) and 40% gave a score of 6 (very strong) and the rest 20% respondents gave a score of 5 (strong plus). While 40% of contract's respondents also gave a score 7 and 43% gave score 6 and the rest 17% gave score 5 to geological risk.

The cost risk mean score was slightly below the geological risk, an overall mean score of 5.7 on the view of company's respondents and of 6.0 on the view of contract's respondents. As a whole those two cost citeria was valued mean of 6.0 by company's respondents and 6.1 by contract's respondents (see Figure 4.33). It suggests on the view of entire respondents the costs criteria in Indonesia were very costly.

Moreover, the respondents were also asked on which one of the following variables were the most risky, price risk (PR), fiscal risk (FR), contract risk (CoR) or political risk (PoR). Compared to other risk criteria, Figure 4.33 shows the company's respondents valued the fiscal risk was the most risky criteria (score 5.6), it was followed by price risk, political risk and contract risk was the least among them. As a whole, those four risk criteria had an overall mean score of 5.2 (slightly above strong plus). While contract's respondents valued the price risk (score 5.9) was the most risky criteria, it was followed by fiscal risk, contract risk, political risk and contract risk as the least risky criteria. As a whole, on the view of contract's respondents those four risk criteria had an overall mean score slightly over the mean score of company's respondents (score 5.5). It suggests the risks criteria in Indonesia valued also as very important citeria in increasing the cost and reducing the revenues but slightly below the costs criteria.

In addition to those criteria above, the respondents also were asked about the strength of other criteria to be considered in decision-making process to enter the petroleum E&P venture. The four criteria asked were the geological petroleum resources potential, the existing PSC framework, "being an established operator", and the regulatory framework. The questions also gave the opportunity to respondents to provide other criteria outside the above criteria being asked.

Figure 4.37 shows that all respondents agreed that the geological potential was the first criteria to be considered in investment decision-making process compared to the other three criteria; the company's respondents gave mean score of

6.3 and contract's respondents of 6.6 (over very important/strong and slightly below the most important/strong parameter).

The company's respondents valued the existing PSC framework as the second ranked after geological potential with mean score of 5.1 (important /strong plus). Next important parameter was "being an established contractor" with mean score of 4.8 (slightly below important /strong plus), and the least was the regulatory framework with mean score of 4.6 (slightly below important/strong plus). While the contract's respondents also valued the geological potential was the most important criteria with an average score of 6.6 (between the most and very important/strong), it was followed by "*being an established contractor*" with mean score of 5.5, the existing PSC framework with mean score of 4.8 and the least was regulatory framework with mean score of 4.4. To sum up, all four criteria above were valued as important /strong plus and over important/strong criteria to be considered in decision making process investing money in petroleum E&P venture in Indonesia.

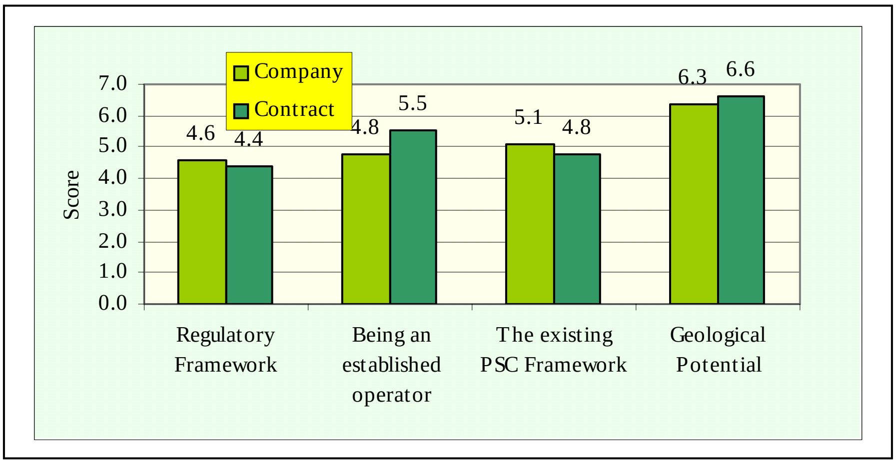


Figure 4.37: Score of decision-making parameter

Furthermore, in addition to those questions, many of the respondents also added a number of criteria that they consider to be paramount of importance in the decision making process to enter petroleum ventures in Indonesia. These criteria were sanctity of contract, economic decision, legal system as well as security, country risk and government relation respectively. Around 50% of the company's respondents and 36% of contract's respondents added the sanctity of contract as an important issue to be considered.

Finally, 88% of the respondents indicated that their view was independent on their present position, or their view will remained before and after securing the petroleum contract. The remaining 22% of the respondents increased their ranking on the regulatory framework and sanctity of contract after concluding the contract.

4.4.2. Operational Issues in Petroleum E&P Venture in Indonesia

In their E&P operation, petroleum companies had experienced a number of operating problems. As the Figure 4.38 shows these issues vary from lack of infrastructure, government intervention, manpower regulation and relation, legal matters, security of the assets, and project approval process. The result of present survey indicated that all the above issues gave strong and over pressing on their operation in Indonesia that needs to be resolved in order to improve the Indonesia's investment climate.

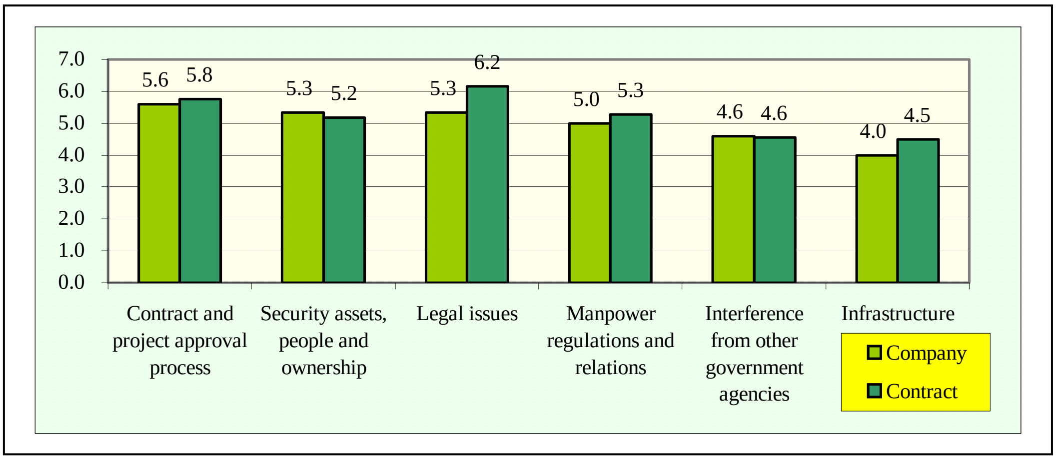


Figure 4.38: Score of Operational Issues

According to the company's respondents, the least operational issue was lack of infrastructure, which was classified in our scoring system as a strong pressing issue (score 4), it was followed by interference from other government agencies in the operation (strong plus pressing), manpower regulation and relation, legal issues, security assets, people and ownership and on the top of the list of pressing issues was the project approval process (very strong pressing issue). While on the view contract's respondents, nearly similar the least operational issue was lack of infrastructure, which was classified as a strong pressing issue, it was followed by interference from other government agencies in the operation (strong plus pressing), security assets, people and ownership, manpower regulation and relation, the project approval process (very strong pressing issue), the project approval process (very strong pressing issue) and on the top of the list of pressing issues was legal issues (over very strong pressing issue).

When they were asked about the pressing institutional relationship, they agreed central government relationship were the most pressing issue on their operation (score 6) in Indonesia (see Figure 4.39).

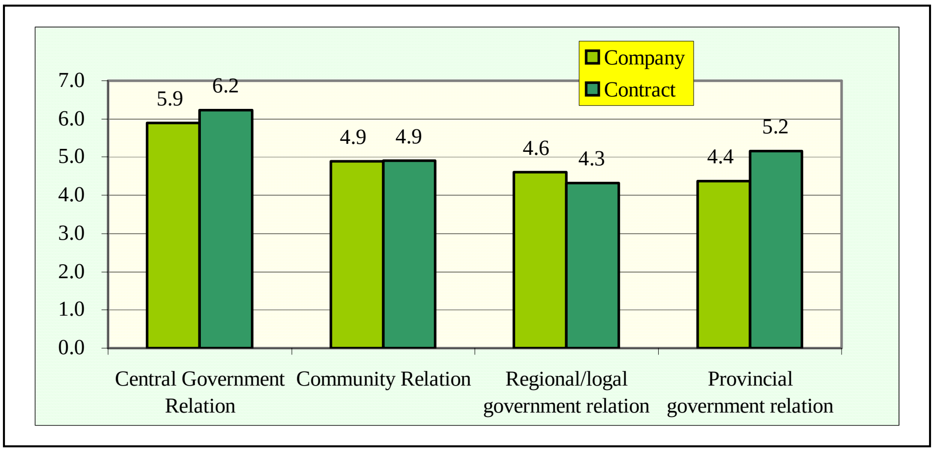


Figure 4.39: Score of pressing institutional relationship parameter

Moreover when they were asked about the quality of relationship with key official of the government, respondents agreed that they had a very good relationship with key officials of provincial government (*Gubernur*), BP Migas and Ministry Energy and Mineral Resources. They also had a good relationship with key officials of Ministry of Finance, Ministry of Manpower and the regional government (*Bupati*). Their relationship with the Parliament (*DPR*) was considered fair (Figure 4.40).

Compared with the result of the PriceWaterHouseCooper survey that was done in 2002 (see Chapter 2 section 2.4), although the scoring system was of the operation issues type and the ranked of operation issues pressing were also rather different, could be concluded that the Indonesian investment climate in year 2002 and 2004 did not improve much. Some operation pressing issues and the institutional relationship issues still gave very strong and over pressure on their operation in Indonesia. These facts suggest of Indonesia's operation pressing issues must be eliminated and the improvements of the quality of institutional relationship are needed as the first priority.

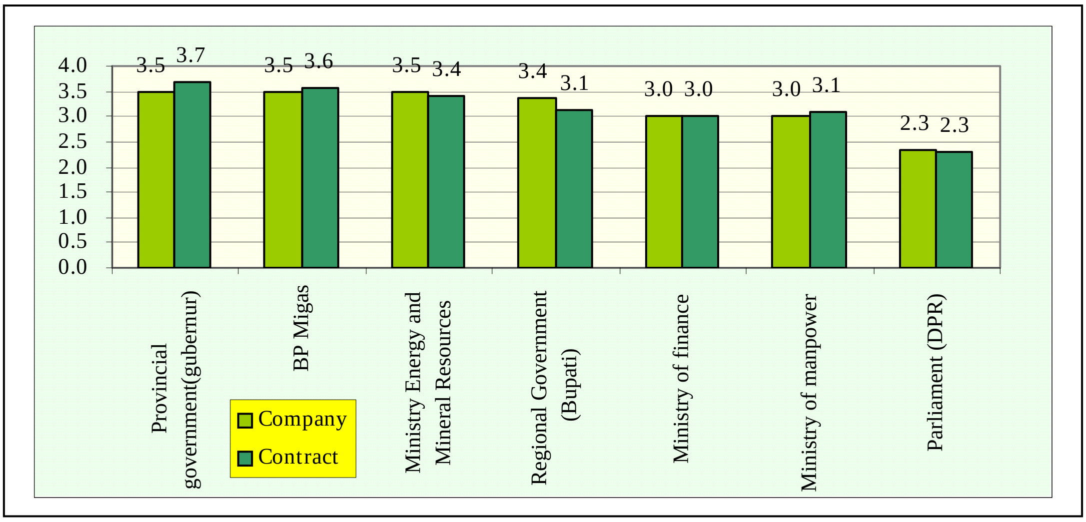


Figure 4.40: Score of company's relationship with key officials

In searching whether the respondents have a clear understanding about Law 22 and 25 on Regional autonomy and Oil and Gas Law number 22/2001, the question regarding these subjects was presented in questionnaires. There were 50% of company's respondents already understood clearly, while 49% of contract's respondents already understood it. Clearly understanding of the content of the law is a must, without it the implementing of this law is wasted and does not give useful benefit; it is suggested the socialisation of those laws is needed.

When the respondent were asked did they have clear understanding the role of Pertamina, BP Migas and Ministry Energy and Mineral Resources Law 22/2001, 80% of company's respondents and 94% of contract's respondents already understood it. However almost all of the respondents commented that the implementation of the law deviated from that stated in the law. The respondents believed that this was due to that lack of understanding on the relative roles of the central, provincial and regional governments. They commented that local governments had frequently acted like warlords and they levied regional taxes added to the tax burden of the PSC. In addition to lack of enforcement, the local and regional government seem were not aware that the policy on oil and gas industry was still handled by the central government. The local and regional governments often claimed that they also had the right to audit the contractor's book account. In October 2004, the GOI finally issued the Government Regulation Number 35/2004, which provides the implementation rule for the Law Number 22/2002 on oil and gas. It is hoped that the issuance of the implementation regulation will help in clarifying some of those operational issues.

4.4.3. The Existing Indonesian Production Sharing Contract System

In this section, the respondents were asked whether the existing Indonesian PSC type is still acceptable to attract investor to invest in E&P venture in Indonesia. They also were asked about the improved financial terms in the existing Indonesian PSC system that they like to see and their comments on the other types of contract, named Modern RAT and RSC.

For the first question, 70% of the company’s respondents and 64% of the contract’s respondents agreed that PSC was still acceptable to attract investor to engage in E&P venture in Indonesia. PSC system already had been agreed by their home office were the reasons of their choices. They also said that PSC terms as stipulated in the existing contracts (pre Law no.22/2001) has provided a fair balance of risk and reward in most cases. However, certain clauses in Law no.22/2001 had reduced the PSC terms attractiveness and the problem laid in the implementation, which eliminate bureaucracy is needed as the first priority, in addition to the improving financial terms.

The respondents commented that the PSC had been working well in the first ten years of its introduction (1966-1976). Pertamina had acted a shield between the PSC and the bureaucrat in the government, allowing the contractors to focus in carrying the work program. Such a strong point of PSC had gone since the eighties and in fact it was getting worse. That being the case, the investors were better off being their own master in their contract area. They also commented that uncertainty of fiscal regime after Law No.22 must be eliminated and some improvement of financial terms were needed, such as improving terms for marginal field and the DMO price after 5 years DMO holiday price needed to be raised from the current figures.

When they were asked about other types of contract, 30% of company's respondents and 36% of contract's respondents recommended the RAT system to replace the PSC system in making Indonesia more competitive internationally. This change may not be acceptable by the government, as it may violate the Constitution and due the fact that the PSC has been widely been accepted worldwide. We postulate that such recommendation had been triggered by frustration among the operators on the government intervention in the operation.

Also, all the respondents said that the financial terms of the existing PSC were needed improvement. They suggested that improving the financial term above should be based on reasonable economic views. More over additional incentives and elimination of economic and political uncertainties were required to increase the exploration activities for higher risk prospects in the conventional and frontier areas, and development of small or marginal fields. Frontier area was a moving target, and the risk was higher as the water depth and remoteness increases.

The following lists the suggested improved terms for the PSC:

1) Increasing production sharing split for contractor especially for marginal field, frontier and deep-water area.
2) Increasing the investment credit both for the conventional and frontier areas and expanding the scope to include facilities cost and operating cost.

3) Extending time of the DMO holiday price from the existing 5 years to 10 years and eliminate the requirement for the frontier areas.
4) In addition to increasing the price to 25% of the market price and revising computation method. Under the existing contract the 25% for DMO was computed based on total production, and the respondents recommended that the DMO be computed based on the production after cost recovery.
5) Reducing the FTP for conventional areas and eliminate it for frontier.
6) The VAT and import taxes and duties for capital and operation items during the exploration phase should continue to be borne by the state and the implementation of it need to be simplified. GOI already responded this issue. In March 2005, the Ministry of Finance issued the Ministry Finance Regulation Number 20/PMK.010/2005 dated March 3, 2005, which provided the "*Pembebasan PPN, Pajak penjualan bea masuk dan pajak pasal 22 impor peralatan untuk explorasi*" It is hoped it could resolve the problem.
7) Tax on profit or dividend shall only be payable when it was actually paid and shall be reduced if the profits was reinvested.
8) To increase the recoverable reserves, exploration activities need to be maintained and this could be accomplished by allowing the tax-consolidations between the contracts. It was particularly important for exploration in frontier, remote, deep-water areas and the development of marginal fields. The respondents stated that the stranded, small reserves must be addressed through incentives of existing terms or these reserves will lost forever.

In addition to the financial terms, the respondent agreed that continueing improving the regulatory framework is a must. The measures include continuing observance of contract sanctity involving the improvements in regulatory system; stability and longevity of *rules*; clarification of the roles of MIGAS, BP Migas, BPKP and Ministry of Finance; to improve the coordination and allocation of responsibilities between central and regional authorities; and reduction of GOI involvement in *micro management* such tendering system, personnel issues and others. While recognizing the GOI sovereignty, the contractors basically like to see that the GOI limits its role to supervision and monitoring through a simpler and transparent approval process, in addition to guarantee the security of the investment.

CHAPTER 5

CONCLUSION AND RECOMMENDATION

5.1. Conclusion

The conclusions of the study are presented following the similar sequence of the objectives of the study mentioned in the Chapter 1. With the scenarios and assumptions applied in the study, the conclusion of the study can be reached are presented below.

5.1.1. Commercial Performances of Indonesian Production Sharing Contracts

The commercial performances of the PSC1 system during 1966 to 2003 period were attractive on the contractor's point of view and gave sufficient benefit for the GOI, but not appropriate to oil field with production rate below 50 MBOPD. The PSC1 not only had the highest number of contract signed, but also had the highest productivity and commercial performance than the other PSC types. However declining tendency on the productivity and commercial performances of the Indonesian PSC system applications occurred after the PSC1 time frame. These facts suggest that incentives are needed in order to increase the commercial performances, which hopefully increase the Indonesia's petroleum E&P investment's attractiveness. The conclusion is similar with the valuation of some investors and writers as mentioned in Chapter 1 and 2.

The commercial performances for any Indonesian locations (western-part, eastern-part, onshore, offshore) on average and as one field were attractive. Empirical evidence showed that western-part of Indonesia had become mature province. In contrast, the eastern-part had low number contracts signed and high number of unexplored basins. Moreover mostly of these unexplored basins were located in deep water and remote areas known as frontier areas. Evidently, petroleum E&P activities in these areas have higher risks and require higher expenditures than other areas. Therefore, more lenient petroleum contract terms and special incentives are needed to boost the exploration investment level, particularly in frontier areas, in order to increase the reserves size and production capacity.

5.1.2. Some PSC Variables as Incentives

Applying the principal agent theory model means acknowledging the reservation utility of the petroleum company that is replaceable by its rate of return expects from a comparable project elsewhere, and or, at least matched. At the same time the host government has to solve the incentive constraint since the host government wish for the guarantee on receiving maximum revenue from the venture. Therefore the utility of working hard (to perform the contract) should be higher than the utility of shirking. It can be understood that the profit of the first case has to be larger than the second case. For that reason the host government has to pay the petroleum company x units above his reservation utility for the contract to be optimal. Government must consider these principles in the decision-making policy in offering the petroleum contractual arrangement.

Based on the premise, higher risk investments should be balanced with higher reward to the contractor. The host government must be aware and accepts that higher risks investments, might suggested GOI income expectation be lowered. Due to its nature, higher risk investment needs more incentives to raise the reward to the petroleum company. Incentives given should be based on reasonable economic and given on the whole life cycle of the venture.

Given the principles above, the analysis found that first the Fifth Incentives Package (IP5) that was offered by GOI in 2003 was commercially attractive for oil field with production rate over 50 MBOPD. However more incentives are needed for oil fields with production rate below 50 MBOPD.

Secondly, improvements of some PSC variables, as incentives are needed, and should be offered based on its production rate profile. Incentives could be considered to attract investor for the field with production rate below 10 MBOPD, in order, of their impact strengths (from the strongest to the least impact) were: reducing the FTP size and shared between GOI and contractor as its production sharing split; recovering the capital expenditures without depreciation; increasing the investment credit; increasing the DMO price and DMO holiday price; reducing tax rate and increasing the contractor production sharing split from their highest figures of Fifth Incentives Package terms.

For the oil field with production rate between 10 – 50 MBOPD, the recommended incentives, in order, of their impact strengths (from the strongest to the least impact) were increasing contractor production sharing split; reducing the tax rate; recovering the capital expenditures without depreciation method; reducing the FTP rate; increasing the DMO holiday price and the DMO holiday price from their lowest figures of the Fifth Incentives Package terms. The terms proposed by the respondents can be considered be applied.

Thirdly, the FTP requirement is still needed; on the other hand the consistency of the main terms of PSC system must also be honoured. Moreover the result of simulation cash flow analysis of FTP's impact has concluded that the provision of 100% FTP for GOI (as offered in IP5) would be a disincentive factor for the development of the entire field cases, it is contradicting with the objective of giving incentive by lowering the FTP under the IP5 (see subsection 4.2.2.1). Therefore, the FTP term, which is currently 100% for GOI under the IP5, is suggested to be lowered and shared between the contractor and GOI, in proportion to the production sharing split as specified in the contract.

Fourth, under the assumptions described in the study, as specified in Chapter 3 section 3.2.3, Monte Carlo simulations concluded that from the contractor's financial aspect, tax consolidation scheme was more attractive incentive compared to increase in production sharing split. It did not only give higher NPV@25% but also reduced the exploration risk. However tax consolidation idea was less attractive to the GOI, not only it reduced GOI's NPV@25% but it also posed financial risk to the GOI. Unless securing additional reserves to supply the ever-increasing domestic energy need and developments of local economy due to multipliers effect of petroleum activity are deemed to be more important, the application of tax consolidation is not likely to be beneficial to GOI.

5.1.3. The Most Desirable Petroleum Contract System for Indonesia on the View of Petroleum Company

The analysis found that the respondents' opinion and judgment were consistent with their experiences. *Small company* focus on current production because it is needed the steady cash income from its production. In evaluating the benefit criteria, the *small company* had placed the current production as the most significant criteria in impacting the benefit stream. On the other hand, consistent with their better knowledge in the geology of the area, given their long years of operation (over 33 years) in western-part of Indonesia, the *medium company* and *large company* considered the reserve as the most significant criteria.

Similarly, in the cost hierarchy structure analysis, *small company* and *medium company* considered that the geological risk was the most costly criteria; while the *large company* view the cost risk was more important criteria in decision making process. This was consistent with the fact that given the years of operating experiences, the geological risk in the western part of Indonesia area had been very well assessed, while with limited budget the *small company* and *medium company* operating in the eastern part of Indonesia had to be more selective in developing the exploration prospects.

In the risk hierarchy analysis, *small company* and *large company* placed the price risk above the fiscal risk, while the contract risk and political risk were considered to have less impact. In contrast the *medium company* view placed fiscal risk (score 7) far above price risk (score 4), while the contract risk and political risk were considered to have less impact.

It can be concluded, the benefit cost risk analysis involving AHP could be used in identifying the most desirable petroleum contract system of petroleum E&P venture. Given recent Indonesia's geological potential, economics, social and political condition, all respondents seemed to choose the Modern Concessionary or Modern Royalty and Tax (RAT) system as the most desirable petroleum contract system for Indonesia compared to the existing Production Sharing Contract (PSC) and Risk Service Contract (RSC).

5.1.4. Investment Climate of the Petroleum Business in Indonesia

First, respondents rated geological potential, cost, risk, the existing PSC framework, being an established contractor, regulatory, contract sanctity criteria as strong plus or more to be considered in the decision making process of investing money in petroleum E&P venture in Indonesia.

Second, the Indonesia's cost risk, geological risk and the entire risk variables of Indonesia were very costly and were rated as very strong or more criteria in reducing the revenues.

Third, the Indonesian investment climate during 2004 did not improve yet. Some operational issues were rated as strong or more pressing on the petroleum companies operation in Indonesia. The following lists the operational issues in the order its pressing importance, from the least to the most pressing, lack of infrastructure; interference from other government agencies in the operation; security assets, people and ownership; manpower regulation and relation; the project approval process (very strong pressing issue); and on the top of the list of pressing issues was legal issues (over very strong pressing issue).

Fourth, the existing Indonesian PSC framework was still favoured highly by respondents (70% of company's and 64% of contract's respondents), while the rest recommended that Indonesia should consider changing the PSC system to RAT system. The main problems were not on the PSC system, but on the implementation of the PSC system. Eliminating bureaucracy was needed as the first priority, in addition to improving the financial terms.

Fifth, only 50% of company's and 49% contract's respondents had a clear understanding about the three new laws, Laws 22 and 25 on Regional autonomy and Oil and Gas Law number 22/2001, suggesting that socialisation of those laws was needed. In contrast, 80% of company's respondents and 94% of contract's respondents had clear understanding on the role of Pertamina, BP Migas and Ministry Energy and Mineral Resources according to the Law 22/2001. However, almost all of them commented that the implementation of the laws deviated from what stated in the laws. The respondents believed that this was due to that lack of understanding on the relative roles of the central, provincial and regional governments. It was hoped that the issuance of the Government Regulation Number 35/2004, which provided the implementation rule for the Law Number 22/2001 on oil and gas sector would help in clarifying some of those operational issues.

Sixth, the entire respondents agreed that the financial terms of the existing PSC needed improvement and suggested that the improvement on the financial term above should be based on reasonable economic views. More additional incentives and elimination of economic and political uncertainties were required not only to increase the exploration activities for higher risk prospects in the conventional and frontier areas, but also for development of small or marginal fields. This was particularly important for exploration in remote or frontier areas and the development of marginal fields. Respondent said that the stranded, small reserves must be addressed through incentives of existing terms, or, these reserves will be lost forever. And seventh, in order to increase the recoverable reserves, exploration activities need to be maintained and these could be accomplished by allowing the tax-consolidations between the contracts.

It can be concluded that Indonesia's petroleum E&P business investment climate in 2004 still did not improve yet and need to be solved immediately.

In addition to the conditions above, Ernst & Young's study (2005) identified that the Indonesia's investment climate in 2004, with score 48 and obtained red light, was the worst compared to ten oil- and gas-rich countries that were regarded as top prospects for energy investment included: Canada, China, India, Indonesia, Nigeria, Norway, Qatar, Russia, Saudi Arabia, and the United Arab Emirates. The objective of the study was to examine the greatest areas of risk and reward for new U.S. exploration and production projects. A series of questions in the following categories: economic stability and tax administration, government structure and accessibility, legal and regulatory systems, the infrastructure in place to support oil and gas operations, and the availability of skilled workers. The questions were scored on a 100-point scale, and, based on these totals, were assigned a red, yellow, or green light. A score of 80% or better was considered green, with few barriers to foreign investment. A score of 60 to 79% was considered yellow, or proceed with caution. A score of less than 60% was considered red, and likely to involve challenges. The study found some of the common barriers in Indonesia include: an instable economy, a lack of channels for reporting unethical behaviour, complex or bureaucratic government that is difficult to navigate, and unreliable or under-developed electric, communications and information technology infrastructures.

Many problems above need be resolved immediately in order to improve the investment climate in Indonesia. In improving the investment climate, in addition to contract sanctity, the four universal principles with respect to the contract law i.e. freedom of contract, *pacta sunt servanda*, good faith and consensualism must be honoured in the entire process of petroleum E&P venture, from the regulatory framework and its implementation thru entire operations of the petroleum E&P venture.

To achieve it, according to respondents, in addition to improve the PSC financial terms, the GOI should continue to improve the regulatory framework and its implementation. The measures include continuing observance of contract sanctity involving the improvements in regulatory system and its implementation; stability and longevity of rules; clarification of the roles of MIGAS, BP Migas, BPKP and Ministry of Finance; to improve the coordination and allocation of responsibilities between central and regional authorities; and reduction of GOI involvement in micro management such tendering system, personnel issues and others; and socialisation of the laws, government regulations, procedures to shareholders. While recognizing the GOI's sovereignty, the contractors basically would like to see that the GOI limits its role to supervision and monitoring through a simpler and transparent approval process, in addition to guaranteeing the security of the investment.

5.2. Recommendation

The role of Indonesia's petroleum activities and revenues are very important for Indonesia, not only to supply energy and to support the GOI revenues, but also due to their multiplier effects on the development of other industries that support the petroleum E&P operation and creating work and job opportunities for the Indonesia's community. Moreover the financial strength of GOI decreased significantly and the Indonesia's net oil importer position must be halt. For that reason the direct private petroleum E&P investments in Indonesia are still needed and must be increased. The GOI must try to search for any possible way to achieve it.

The results of the study show that the recent position of Indonesia's E&P investment attractiveness in global competition to attract scarce fund investment was reduced. Furthermore exploration activities must be increased in frontier areas and deep water. Consequently GOI must offer more lenient contract terms and more attractive incentives to increase the attractiveness of the Indonesia’s petroleum E&P investment. In short term, the GOI revenues might decrease due to more lenient contract terms/incentives. However, if the lenient contract terms and incentives to offer was attractive enough to increase the petroleum E&P investment level in Indonesia, in the long run the reserves size and the production capacity most likely will increase, and as the result the GOI revenues will increase too.

Therefore based on the results of the study, in order to increase the attractiveness of the Indonesia’s petroleum E&P investment, the study recommends as follows,

(1) Improvements of some PSC variables as incentives should consider to be offered based on its production rate profile (detail see sub section 5.1.2). The proposed respondents terms can be considered be applied.
(2) Since tax consolidation application in frontier areas posed financial risk to the GOI, hence it could not be used as incentives. In the meantime Indonesia needs to boost the exploration investments level in frontier areas. Consequently GOI should consider using the Modern RAT system strictly only for exploration investment in new and very high-risk areas and isolated frontier areas.
(3) The most important aspect immediately needs to be put in effect is improving the Indonesia’s investment climate condition (see detail in section 5.1.4).

For future research, the following studies are suggested:

(1) A comprehensive comparative petroleum contract system study between Indonesia and other countries, not only from financial point view, but also involving other criteria such as geological potential, costs, price risk, market risk, fiscal risk, contract risk, political risk and others using AHP method.
(2) A study to analyse the modern RAT system from legal point of view. On the view of investor, the RAT system was the most desirable petroleum contract system. On the other hand the traditional RAT system was regarded by the Indonesia as being far too generous to foreign companies at the expenses of the country. Meanwhile the current development of modern RAT system shows that this system can be modified to reduce its negative side.

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Appendix A

QUESTIONNAIRE

Through this questionnaire we would like to know your expert judgment and opinion about some parameters in petroleum E&P investment in Indonesia to gain a better sight of the issues in order to attract investors into petroleum E&P industry in Indonesia. Thank you very much for your cooperation and interest.

Responses will be used solely for academic purposes and will be kept strictly confidential.

SECTION A: BACKGROUND

For decades Indonesia's upstream petroleum (E&P) venture has been viewed by international petroleum investor as an attractive destination for investment. However, the changes in the Indonesia's petroleum resources potential, economical, social and political conditions seem to have made the existing Indonesia's fiscal system Production Sharing Contract (PSC) look inefficient.

The objectives of the study are to answer following questions: Is the existing Indonesia's PSC still efficient to attract investors in petroleum E&P industry in Indonesia? Or does the existing fiscal system need to be changed? If the answer is that the existing Indonesia's PSC is still attractive, then which terms must be enhanced to raise the attractiveness of the existing Indonesia's PSC system?

In this study, there are three fiscal systems that can be selected for petroleum investment, namely: the Royalty and Tax (RAT), Risk Service Contract (RSC) and the existing Indonesia's Production Sharing Contract (PSC).

In RAT system, the petroleum resources may be privately owned through government licensing. The government takes shares from only royalties, which are paid before production and taxes after production.

In RSC system, the government retains ownership of petroleum resources, while the petroleum company will explore at its sole risk as the contractor of the government. In return, if exploration efforts are successful, the government allows the contractor to recover those costs through sale of the petroleum and pays the contractor a fee based on a percentage of the remaining revenues.

In PSC system, the government retains ownership of petroleum resources, while the petroleum company will explore at its sole risk and, in the case of commercial discovery, develop and produce the resource. The contractor will recover its expenditures for exploration and production, and the remainder will be shared between the host government and the contractor and can be regarded as payment or compensation for the risk taken and service rented. In this study the PSC system is the existing or current Indonesia's PSC.

This study will be done in two approaches, economic analysis and holistic approach through benefit-cost-risk analysis with Analytic Hierarchy Process (AHP).

SECTION B: EXPERIENCES IN E&P OPERATION IN INDONESIA

B. 1. COMPANY BACKGROUND INFORMATION

If you are an Executive in Oil Company, please tick the appropriate boxes to describe your company. Others go to Section B.3.

1) How long has your company been operating in Indonesian upstream petroleum operations? …………years.

2) Please indicate the size of your company's activities in terms of total Annual Expenditure for Exploration, Development and Production (average for the last five years).

Less than US $ 20 million	
US$ 20 – 100 million	
Over US$ 100 million	

3) Please indicate the size of your company's activities in terms of total annual Oil Production (average for the last five years)

Less than 10 MBOPD	
10 – 50 MBOPD	
Over 50 MBOPD	

4) You describe your company as:

A National Oil Company	
A Foreign Oil Company	
Other, please specify:…………	

5) Beside Indonesia, your other company's operations are located in the following countries:
……………………………………………………………………………………
……………………………………………………………………………………

6) Your present upstream activities in Indonesia include:

Onshore		Frontier area	
Offshore		Deep water: …………. m	
Both onshore-offshore		Other: specify…………	

7) Your present upstream activities are in:

Western part of Indonesia	
Eastern part of Indonesia	

8) Your company has the following petroleum contractual agreements with Indonesia Government:

Type of agreements	**How many**
Production Sharing Contract (PSC)	
Enhanced Oil Recovery Contract (EOR)	
Joint Operation Body (JOB)	
Technical Assistance Contract (TAC)	
Joint Operation Agreement (JOA)	
Other: specify…………..	

B. 2. INVESTMENT DECISION

1) Please give your score from 1 to 7 in the order of its significance the parameters that are considered in your decision to enter the petroleum venture in Indonesia (Note 7 = the most significant, 6 = very strong, 5= strong plus, 4 = strong, 3= moderate, 2= weak, and 1 is the least significant).

Parameter	**Score**
Geological Potential	
The existing PSC Framework	
Being an established operator	
Regulatory framework	
Other: please specify…………	
……………………………………………	
…………………………………………….	

2) After securing new petroleum contract and the operation commences, do you find the above ranking needs to be changed?

☐ YES ☐ NO

3) If your answer in # 2 above is “Yes”, please make a new scoring from 1 to 7 in the order of its significance (Note 7 is the most significant and 1 is the least significant).

Parameter	Score
Geological Potential	
The existing PSC Framework	
Being an established operator	
Regulatory framework	
Other: please specify…………	
……………………………………………	
…………………………………………….	

B. 3. OPERATIONAL ISSUES

1) Please give your score from 1 to 7 in the order of its importance according your experience/opinion the strength of pressing operation issues that affect your company operation in Indonesia (Note 7 is the most pressing and 1 is the least pressing).

Operation issues	Score
Legal issues	
Contract and project approval process	
Community Relations	
Central Government relations (BP-Migas, Ministry of Energy and Resources, Ministry of Finance, Ministry of Manpower, DPR etc.)	
Provincial government (Gubernur etc.)	
Regional/Local Government relations (Bupati etc.)	
Security of assets, people and ownership right	
Manpower regulations and relations	
Interference from other government agencies, such as tax authorities	
Infrastructure	
Other (specify):	

2) Institutional Relationship:

a) Do you have a clear understanding on the roles of central, provincial and regional governments under the Laws Number Law 22/1999 on Regional Autonomy and Law 25/1999 on Fiscal Decentralization and the Oil and Gas Law Number 22/2001?

☐ YES ☐ NO

If your answer is "NO" please specify

a) Do you have a clear understanding on the roles of PERTAMINA, BP MIGAS and Ministry of Energy and Mineral Resources under the Oil and Gas Law Number 22/2001?

☐ YES ☐ NO

If your answer is "NO" please specify

3) <u>Government – Company Relationship.</u>

If you are an executive in Petroleum Company, please give your experience on your company's relationship with key officials. Others, according to your opinion, please give your opinion about company's relationship with key officials. (Note: 5 = excellent, 4 = very good, 3 = good, 2 = fair, and 1 = poor)

Relationship with….	**Score**
Regional government (Bupati)	
Provincial government (Gubernur)	
BP MIGAS	
Ministry of Energy and Mineral Resources	
Ministry of Finance	
Ministry of Manpower	
Parliament (DPR)	

B. 4. INDONESIA'S FISCAL SYSTEM

1) If you are an executive in Petroleum Company, is the Existing Indonesia Production Sharing Contract system still acceptable to your company? Others, according your opinion, is the Existing Indonesia Production Sharing Contract type still acceptable to attract investor to invest in E&P industry in Indonesia?

☐ YES ☐ NO

Your reasoning:

2) What are the improved financial terms in the existing Indonesia's PSC system that you like to see, in order to attract investors to invest in Indonesia?

Contract Terms	**Conventional**	**Frontier**	**Reason**
Oil Sharing formula			
Gas Sharing formula			
Investment Credit			
DMO			
FTP			
Tax			
Tax consolidation			

Other: specify			

3) If your answer “NO”, what is the type of contract that you recommend along with your reasoning:

☐ Royalty and Tax ☐ Service Contract

☐ Other: specify:

Your reasoning:

SECTION C: BENEFIT-COST-RISK WITH ANALYTIC HIERARCHY PROCESS (AHP)

C. 1. METHODOLOGY

The Analytic Hierarchy Process (AHP) is a theory for priority measurement, developed by Saaty, which provides a framework of logic and problem solving which has been widely applied by organizations and business worldwide. It is a process for organizing perceptions, feelings, judgments, and memories into a hierarchy of forces that influences decision results.

The AHP meets the steps in decision making which involves: structuring a problem, eliciting judgments, representing those judgments with meaningful numbers, using the numbers to calculate the priorities of the elements of the hierarchy, synthesizing the results to determine an overall outcome, and finally analysing the sensitivity to changes in judgments.

Any investment decision has several favourable and unfavourable concerns. Some of them are certain; others are less certain and have a likelihood of materializing. The favourable certain concerns are identified as benefits while the unfavourable ones are identified as costs. The uncertain concern of a decision is negative risks that can entail. The difference between cost and risk is: Cost is uncertain/negative impact that can entail immediately; meanwhile risk is negative impact that could entail in the future.

In benefit-cost-risk analysis with AHP each of these concerns utilizes as a separate structure for decision. The study starts with a benefit control structure, then a cost control structure and ends with a risk control structure. These three structures can be utilized to assess benefit / (cost x risk) outcome. Each parameter will be observed at a different threshold of intensity, and that such thresholds will be prioritised according to their importance. Each alternative is evaluated only in terms of its highest-priority threshold level.

Benefit-cost-risk analysis with AHP will be illustrated in this study to answer following questions: Is the existing Indonesia's PSC still efficient to attract investors in petroleum E&P industry in Indonesia? Or does the existing fiscal system need to be changed? If the answer is that the existing Indonesia's PSC is still attractive, then which terms must be enhanced to raise the attractiveness of the existing Indonesia's PSC system?

Parameters for comparison

In the study, we will try compare various parameters that may be pertinent in investment decision process, in particular relates to reserves. The parameters would be compared are:

(1) ***Reserves (R)*** proved and probable, represents the remaining discovered reserves that have not been produced yet plus the potential amount of undiscovered reserves in that area/field/basin/country.

(2) ***Total Reserve Addition in the last 10 years (TRA)*** proved as well probable (P+P), will be considered to know not only the size of the basins but also its timing from discovery. In other words, a relatively new basin will not have added to many reserves in the last 10 years; however, an old one may have historically added an important amount of reserves, but not in the last 10 years since it may be a mature basin.

(3) ***Current Production (CP)*** data refers to the latest available data of annual petroleum production.

(4) ***Reserve/Production Ratio (R/P)*** shows the number of years of future production at current production rates and is defined as,

Reserves/Annual Production

The R/P ratio disregard production declines or any reserve growth.

(5) ***Cost Risk (CR)*** occurs when costs vary irregularly due to unpredicted operational issues such as unexpected side effects that would evolve to decrease the quality of environment during operation; longer in contract and project approval process; legal issues; community relation; government relation; security of assets, people and ownership; manpower regulation and relation; interference from other government agencies; infrastructure, failure in technology might be chosen and others.

(6) ***Geological Risk (GR)*** is the possibility of failure in exploration.

(7) ***Price Risk (PR)*** occurs when price varies irregularly due to ups and downs in demand at some point in time either because of changes in demand behaviour or because of new sources of supply or others.

(8) ***Fiscal Risk (FR)*** occurs due to changes in the fiscal terms such as tax, inflation, or others.

(9) ***Contract Risk (CoR)*** happened when unpredicted revision in the contract element.

(10) ***Political Risk (PoR)*** happens due to changes in the political condition, either by having a new party in power or by some type of coup, implementation of new regulation and others.

The assumptions of this study are:

(1) Indonesia is treated as one field of petroleum E&P operation.
(2) The income/profit of three alternatives fiscal systems (RAT, RSC and PSC) have the same amount.
(3) All parameters are in the current Indonesia condition.

C. 2. PAIRED COMPARISON BETWEEN PARAMETERS

1) While considering entering the petroleum venture in Indonesia, one of the parameter to be evaluated is what and how much the benefits that might be acquired if you invest in the petroleum E&P project. The benefits of the E&P venture could be known from their petroleum resources potential, involving the Reserves Potential, Total Reserves Addition in the last 10 years (TRA), Current Production (CP) and Reserve/Production Ratio (R/P) of a field/basin/country.

   Please give your score from 1 to 7 in order of its importance (Note 7 is the most important and 1 is the least important) of the parameters below in your evaluation the benefits that might be obtained if you invest in E&P venture in Indonesia, with the assumption that all parameters below are in the current Indonesia's condition.

Parameter	Score
Reserves Potential (R)	
Total Reserve Addition (TRA)	
Current Production (CP)	
Reserve/Production Ratio (R/P)	

2) In applying the cost for valuation, please give your score from 1 to 7 in order of its importance (Note 7 is the most important and 1 is the least important) of the parameters below that will be making additional cost or reducing the revenue.

Parameter	Score
Cost Risk (CR)	
Geological Risk (GR)	

3) In applying the risk for valuation, please give your score from 1 to 7 in the order of its importance (Note 7 is the most important and 1 is the least important) of the parameters below that will be making additional cost or reducing the revenue.

Parameter	Score
Price Risk (PR)	
Fiscal Risk (FR)	
Contract Risk (CoR)	
Political Risk (PoR)	

C. 3. PAIRED COMPARISON BETWEEN ALTERNATIVES

We would like to know your paired comparison judgments to capture the relative dominance of one parameter above other parameter with respect to reach the objective of attracting investor to invest in E&P industry in Indonesia. The answer should be scored according to the fundamental scale that shown in Table 1 below.

Table 1. The Fundamental Scale

Intensity of Importance	Definition	Explanation
1	**Equal Importance/ Desirable**	**Two element contribute equally to the objective**
2	Weak	….between Equal and Moderate
3	**Moderate Importance /Desirable**	**Experience and judgment slightly favor one element over another**
4	Moderate plus	….between Moderate and Strong
5	**Strong Importance/Desirable**	**Experience and judgment strongly favor one element over another**
6	Strong plus	….between Strong and Very Strong
7	**Very Strong or demonstrated Importance/Desirable**	**An element is favored very strongly over another; its dominance demonstrated in practice**
8	Very, very strong	….between Very Strong and Extreme
9	**Extreme Importance/Desirable**	**The evidence favoring one element over another is of the highest possible order of affirmation**
Reciprocals of above	If element i has one of the above nonzero numbers assigned to it when compared with activity j, then j has the reciprocal value when compared with i	If x is 5 times j, i.e., x = 5y, then y = x/5 or y = 1/5 x.
Rationals	Ratios arising from the scale	If consistency were to be forced by obtaining n numerical values to span the matrix.

Examples:

Comparison judgment between RAT and RSC, under Indonesia's Reserves (R) condition.

Question 1:

To reach the objective of attracting investor to invest in petroleum E&P industry in Indonesia, under Indonesia's Reserves (R) condition, which is more important RAT or RSC system?

Answer 1:

- If your answer **RAT is more important than RSC** then cross the box on the left of box at row for RAT.
- If your answer **RSC is more important than RAT** then cross the box on the left of box at row for RSC.
- If they are both "**equally important**", you cross the box "***1***".
- Example answer 1: RSC is more important than RAT.

	RAT	1	2	3	4	5	6	7	8	9
X	RSC	1	2	3	4	5	6	7	8	9

Question 2.:

Under Indonesia's Reserves (R) condition, how much more important is RAT over RSC (or RSC over RAT)?

Answer 2:

- If in your opinion **RSC is of "extreme importance" (number 9) compared to RAT**, then cross the box "9" in the same row of box RSC.
- If they are both "**equally important**", you cross the box "1,".
- If you are not sure with your choice between "**extreme importance**" (number 9) or "**very strongly more important**" (number 7) you could choose number 8 and cross the box "**8**" in the same row of box RSC.
- Example answer 2: **RSC is "very strongly more importance**" (number 7) compared to **RAT**.

	RAT	1	2	3	4	5	6	7	8	9
X	RSC	1	2	3	4	5	6	**7X**	8	9

PLEASE ANSWER THE QUESTIONS BELOW WITH THE SAME METHOD ABOVE.

1) **Comparison judgment under Indonesia's Reserves (R) condition.**

a) Between RAT and RSC.
Under Indonesia's R condition,
- Which is more important RAT or RSC?
- How much more important is RAT over RSC (or RSC over RAT)?

	RAT	1	2	3	4	5	6	7	8	9
	RSC	1	2	3	4	5	6	7	8	9

b) Between RAT and PSC.
Under Indonesia's R condition,
- Which is more important RAT or existing PSC system?
- How much more important is RAT over PSC (or PSC over RAT)?

	RAT	1	2	3	4	5	6	7	8	9
	PSC	1	2	3	4	5	6	7	8	9

c) Between RSC and PSC.
Under Indonesia's R condition,
- Which is more important RSC or existing PSC system?
- How much more important is RSC over PSC (or PSC over RSC)?

	RSC	1	2	3	4	5	6	7	8	9
	PSC	1	2	3	4	5	6	7	8	9

2) **Comparison judgment under Indonesia's Total Reserves Addition (TRA)**

a) Between RAT and RSC.
Under Indonesia's TRA condition,
- Which is more important RAT or RSC?
- How much more important is RAT over RSC (or RSC over RAT)?

	RAT	1	2	3	4	5	6	7	8	9
	RSC	1	2	3	4	5	6	7	8	9

b) Between RAT and PSC.
Under Indonesia's TRA condition,
- Which is more important RAT or existing PSC system?
- How much more important is RAT over PSC (or PSC over RAT)?

	RAT	1	2	3	4	5	6	7	8	9
	PSC	1	2	3	4	5	6	7	8	9

c) Between RSC and PSC.
Under Indonesia's TRA condition,
- Which is more important RSC or Existing PSC system?
- How much more important is RSC over PSC (or PSC over RSC)?

	RSC	1	2	3	4	5	6	7	8	9
	PSC	1	2	3	4	5	6	7	8	9

3) Comparison judgment under Indonesia's Current Production (CP)

a) Between RAT and RSC.

Under Indonesia's CP condition,

- Which is more important RAT or RSC?
- How much more important is RAT over RSC (or RSC over RAT)?

	RAT	1	2	3	4	5	6	7	8	9
	RSC	1	2	3	4	5	6	7	8	9

b) Between RAT and PSC.

Under Indonesia's CP condition,

- Which is more important RAT or existing PSC system?
- How much more important is RAT over PSC (or PSC over RAT)?

	RAT	1	2	3	4	5	6	7	8	9
	PSC	1	2	3	4	5	6	7	8	9

c) Between RSC and PSC.

Under Indonesia's CP condition,

- Which is more important RSC or Existing PSC system?
- How much more important is RSC over PSC (or PSC over RSC)?

	RSC	1	2	3	4	5	6	7	8	9
	PSC	1	2	3	4	5	6	7	8	9

4) Comparison judgment under Indonesia's Reserve/ Production Ratio (R/P)

a) Between RAT and RSC.

Under Indonesia's R/P condition,

- Which is more important RAT or RSC?
- How much more important is RAT over RSC (or RSC over RAT)?

	RAT	1	2	3	4	5	6	7	8	9
	RSC	1	2	3	4	5	6	7	8	9

b) Between RAT and PSC.

Under Indonesia's R/P condition,

- Which is more important RAT or existing PSC system?
- How much more important is RAT over PSC (or PSC over RAT)?

	RAT	1	2	3	4	5	6	7	8	9
	PSC	1	2	3	4	5	6	7	8	9

c) Between RSC and PSC.

Under Indonesia's R/P condition,

- Which is more important RSC or Existing PSC system?
- How much more important is RSC over PSC (or PSC over RSC)?

	RSC	1	2	3	4	5	6	7	8	9
	PSC	1	2	3	4	5	6	7	8	9

5) Comparison judgment under Indonesia's Cost Risk (CR) condition.

a) Between RAT and RSC.
Under Indonesia's CR condition,
- Which is more important RAT or RSC?
- How much more important is RAT over RSC (or RSC over RAT)?

	RAT	1	2	3	4	5	6	7	8	9
	RSC	1	2	3	4	5	6	7	8	9

b) Between RAT and PSC.
Under Indonesia's CR condition,
- Which is more important RAT or existing PSC system?
- How much more important is RAT over PSC (or PSC over RAT)?

	RAT	1	2	3	4	5	6	7	8	9
	PSC	1	2	3	4	5	6	7	8	9

c) Between RSC and PSC.
Under Indonesia's CR condition,
- Which is more important RSC or Existing PSC system?
- How much more important is RSC over PSC (or PSC over RSC)?

	RSC	1	2	3	4	5	6	7	8	9
	PSC	1	2	3	4	5	6	7	8	9

6) Comparison judgment under Indonesia's Geological Risk (GR) condition.

a) Between RAT and RSC.
Under Indonesia's GR condition,
- Which is more important RAT or RSC?
- How much more important is RAT over RSC (or RSC over RAT)?

	RAT	1	2	3	4	5	6	7	8	9
	RSC	1	2	3	4	5	6	7	8	9

b) Between RAT and PSC.
Under Indonesia's GR condition,
- Which is more important RAT or existing PSC system?
- How much more important is RAT over PSC (or PSC over RAT)?

	RAT	1	2	3	4	5	6	7	8	9
	PSC	1	2	3	4	5	6	7	8	9

c) Between RSC and PSC.
Under Indonesia's GR condition,
- Which is more important RSC or Existing PSC system?
- How much more important is RSC over PSC (or PSC over RSC)?

	RSC	1	2	3	4	5	6	7	8	9
	PSC	1	2	3	4	5	6	7	8	9

7) Comparison judgment under Indonesia's Price Risk (PR) condition.

a) Between RAT and RSC.

Under Indonesia's PR condition,

- Which is more important RAT or RSC?
- How much more important is RAT over RSC (or RSC over RAT)?

	RAT	1	2	3	4	5	6	7	8	9
	RSC	1	2	3	4	5	6	7	8	9

b) Between RAT and PSC.

Under Indonesia's PR condition,

- Which is more important RAT or existing PSC system?
- How much more important is RAT over PSC (or PSC over RAT)?

	RAT	1	2	3	4	5	6	7	8	9
	PSC	1	2	3	4	5	6	7	8	9

c) Between RSC and PSC.

Under Indonesia's PR condition,

- Which is more important RSC or Existing PSC system?
- How much more important is RSC over PSC (or PSC over RSC)?

	RSC	1	2	3	4	5	6	7	8	9
	PSC	1	2	3	4	5	6	7	8	9

8) Comparison judgment under Indonesia's Fiscal Risk (FR) condition.

a) Between RAT and RSC.

Under Indonesia's FR condition,

- Which is more important RAT or RSC?
- How much more important is RAT over RSC (or RSC over RAT)?

	RAT	1	2	3	4	5	6	7	8	9
	RSC	1	2	3	4	5	6	7	8	9

b) Between RAT and PSC.

Under Indonesia's FR condition,

- Which is more important RAT or existing PSC system?
- How much more important is RAT over PSC (or PSC over RAT)?

	RAT	1	2	3	4	5	6	7	8	9
	PSC	1	2	3	4	5	6	7	8	9

c) Between RSC and PSC.

Under Indonesia's FR condition,

- Which is more important RSC or Existing PSC system?
- How much more important is RSC over PSC (or PSC over RSC)?

	RSC	1	2	3	4	5	6	7	8	9
	PSC	1	2	3	4	5	6	7	8	9

9) Comparison judgment under Indonesia's Contract Risk (CoR) condition.

a) Between RAT and RSC.

Under Indonesia's CoR condition,

- Which is more important RAT or RSC?
- How much more important is RAT over RSC (or RSC over RAT)?

	RAT	1	2	3	4	5	6	7	8	9
	RSC	1	2	3	4	5	6	7	8	9

b) Between RAT and PSC.

Under Indonesia's CoR condition,

- Which is more important RAT or existing PSC system?
- How much more important is RAT over PSC (or PSC over RAT)?

	RAT	1	2	3	4	5	6	7	8	9
	PSC	1	2	3	4	5	6	7	8	9

c) Between RSC and PSC.

Under Indonesia's CoR condition,

- Which is more important RSC or Existing PSC system?
- How much more important is RSC over PSC (or PSC over RSC)?

	RSC	1	2	3	4	5	6	7	8	9
	PSC	1	2	3	4	5	6	7	8	9

10) Comparison judgment under Indonesia's Political Risk (PoR) condition.

a) Between RAT and RSC.

Under Indonesia's PoR condition,

- Which is more important RAT or RSC?
- How much more important is RAT over RSC (or RSC over RAT)?

	RAT	1	2	3	4	5	6	7	8	9
	RSC	1	2	3	4	5	6	7	8	9

b) Between RAT and PSC.

Under Indonesia's PoR condition,

- Which is more important RAT or existing PSC system?
- How much more important is RAT over PSC (or PSC over RAT)?

	RAT	1	2	3	4	5	6	7	8	9
	PSC	1	2	3	4	5	6	7	8	9

c) Between RSC and PSC.

Under Indonesia's PoR condition,

- Which is more important RSC or Existing PSC system?
- How much more important is RSC over PSC (or PSC over RSC)?

	RSC	1	2	3	4	5	6	7	8	9
	PSC	1	2	3	4	5	6	7	8	9

SECTION D: SUGGESTION

Please give your suggestions, what and how does the Indonesian Government have to do, to reach the objective of attracting investor to invest in E&P industry in Indonesia.

PERSONAL INFORMATION

1) Name: (optional)

2) Occupation (or former occupation) and title in the petroleum sector:

3) Occupation (or former occupation) and title in non-petroleum sector:

4) Please indicate your number of years of experiences in the petroleum sector.

Less than 5 years	
5 – 10 years	
More than 10 years	

Date : - - 2004

Signature:

Appendix B1

Case A.base case: Cash flow simulation of small (marginal) oil field using IP5 figures

1000USD

	%	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
1 Annual Expenditures (000 USD)																	
a. Capital Expenditures	22.3%	557	638	628	639	586	592	468	398	581	683	542	868	1,114	1,110	1,469	1,171
b. Non Capital & operating expenditures		1,942	2,221	2,188	2,226	2,041	2,062	1,632	1,386	2,023	2,378	1,886	3,025	3,881	3,868	5,115	4,079
c. Total Expenditures		2,499	2,859	2,816	2,865	2,627	2,654	2,100	1,784	2,604	3,061	2,428	3,893	4,995	4,978	6,584	5,250
2 Lifting																	
a. Oil (000 BL)			547	522	471	529	431	427	365	357	329	312	259	203	235	272	322
b Oil Prices (USD/B)			1.89	1.93	3.02	10.06	10.29	10.24	12.29	10.99	16.20	27.26	35.13	35.63	24.66	27.25	25.37
c Gas (000 CFT)																	
d. Gas Price(USD/CFT)																	
e Oil/day (000 BL)			1.499	1.430	1.290	1.449	1.181	1.170	1.000	0.978	0.901	0.855	0.710	0.556	0.644	0.745	0.882
3 Gross Revenues before FTP		0	1,035	1,009	1,423	5,324	4,435	4,374	4,487	3,923	5,329	8,504	9,099	7,232	5,795	7,411	8,169
a. FTP	10%	0	104	101	142	532	444	437	449	392	533	850	910	723	580	741	817
4 Gross Revenue after FTP		0	932	908	1,281	4,792	3,992	3,937	4,038	3,531	4,796	7,654	8,189	6,509	5,216	6,670	7,352
5 Cost Recovery																	
a. Unrecovered cost		0	(1,942)	(4,751)	(7,053)	(9,097)	(7,426)	(6,893)	(5,643)	(3,932)	(3,551)	(2,403)	0	0	0	(668)	(1,609)
b. Current Year Operating Cost		1,942	2,221	2,188	2,226	2,041	2,062	1,632	1,386	2,023	2,378	1,886	3,025	3,881	3,868	5,115	4,079
c. Current Depreciation	5ys DDBL	0	299	381	446	481	792	577	535	534	572	535	602	773	882	995	1,117
d. Total Cost Recovery		1,942	4,462	7,320	9,725	11,619	10,280	9,101	7,564	6,489	6,502	4,825	3,626	4,654	4,749	6,778	6,804
e. Current Investment Credit	102.14%	0	1,221	642	653	599	605	478	406	593	697	553	887	1,138	1,134	1,500	1,196
f. Total Recoverable		1,942	5,682	7,962	10,378	12,217	10,885	9,580	7,970	7,082	7,199	5,378	4,513	5,792	5,884	8,279	8,000
g. Current Maximum cost recovery		0	932	908	1,281	4,792	3,992	3,937	4,038	3,531	4,796	7,654	8,189	6,509	5,216	6,670	7,352
h. Actual cost recoverable		0	932	908	1,281	4,792	3,992	3,937	4,038	3,531	4,796	5,378	4,513	5,792	5,216	6,670	7,352
6 Equity to be split		0	0	0	0	0	0	0	0	0	0	2,275	3,676	717	0	0	0
7 GOI Share																	
a. GOI Equity share	37.5%	0	0	0	0	0	0	0	0	0	0	853	1,378	269	0	0	0
b. GOI share from FTP	100%	0	104	101	142	532	444	437	449	392	533	850	910	723	580	741	817
c. Domestic Requirement		0	0	0	0	0	0	0	0	0	0	997	1,066	848	679	868	957
d. Gov.Tax Entitlement	44%	0	0	0	0	0	0	0	0	0	0	431	932	325	0	0	0
e. Total GOI Share		0	104	101	142	532	444	437	449	392	533	3,131	4,286	2,164	1,259	1,610	1,774

Appendix B1

Case A.base case: Cash flow simulation of small (marginal) oil field using IP5 figures

000USD

	%	17	18	19	20	21	22	23	24	25	26	27	28	29	30	Total	Mean
1 Annual Expenditures (000 USD)																	
a. Capital Expenditures	22.3%	1,188	835	1,303	1,177	1,353	1,645	1,428	1,283	1,213	788	998	891	584	642	27,374	912
b. Non Capital & operating expenditures		4,139	2,908	4,538	4,099	4,712	5,730	4,972	4,470	4,223	2,744	3,476	3,103	2,032	2,237	95,334	3,178
c. Total Expenditures		5,327	3,743	5,841	5,276	6,065	7,375	6,400	5,753	5,436	3,532	4,474	3,994	2,616	2,879	122,708	4,090
2 Lifting																	
a. Oil (000 BL)		308	474	412	479	456	442	407	382	384	326	288	294	240	202	10,675	368
b Oil Prices (USD/B)		18.57	15.61	13.90	15.05	18.99	15.97	14.88	14.18	13.45	15.34	18.23	16.85	11.13	16.49	16.24	16.24
c Gas (000 CFT)		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
d. Gas Price(USD/CFT)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
e Oil/day (000 BL)		0.844	1.299	1.129	1.312	1.249	1.211	1.115	1.047	1.052	0.893	0.789	0.805	0.658	0.553	1.009	1.009
3 Gross Revenues before FTP		5,719	7,399	5,727	7,209	8,660	7,057	6,055	5,417	5,163	5,002	5,249	4,954	2,670	3,331	157,161	5,239
a. FTP	10%	572	740	573	721	866	706	606	542	516	500	525	495	267	333	15,716	524
4 Gross Revenue after FTP		5,147	6,659	5,154	6,488	7,794	6,351	5,450	4,875	4,647	4,502	4,724	4,459	2,403	2,998	141,445	4,715
5 Cost Recovery																	
a. Unrecovered cost		(648)	(2,047)	(251)	(2,203)	(2,168)	(1,674)	(3,965)	(6,339)	(8,579)	(10,740)	(11,063)	(11,989)	(12,598)	(13,744)	(142,978)	(4,766)
b. Current Year Operating Cost		4,139	2,908	4,538	4,099	4,712	5,730	4,972	4,470	4,223	2,744	3,476	3,103	2,032	2,237	95,334	3,178
c. Current Depreciation	5ys DDBL	1,193	1,103	1,238	1,152	1,206	1,232	1,392	1,335	1,346	1,276	1,155	1,055	920	2,251	27,374	912
d. Total Cost Recovery		5,980	6,057	6,027	7,454	8,086	8,636	10,330	12,143	14,148	14,760	15,694	16,147	15,551	18,232	265,686	8,856
e. Current Investment Credit	102.14%	1,214	853	1,331	1,202	1,382	1,680	1,458	1,311	1,239	805	1,019	910	596	656	27,960	932
f. Total Recoverable		7,194	6,910	7,357	8,656	9,468	10,317	11,788	13,454	15,387	15,565	16,713	17,057	16,147	18,888	293,645	9,788
g. Current Maximum cost recovery		5,147	6,659	5,154	6,488	7,794	6,351	5,450	4,875	4,647	4,502	4,724	4,459	2,403	2,998	141,445	4,715
h. Actual cost recoverable		5,147	6,659	5,154	6,488	7,794	6,351	5,450	4,875	4,647	4,502	4,724	4,459	2,403	2,998	134,777	4,493
6 Equity to be split		0	0	0	0	0	0	0	0	0	0	0	0	0	0	6,668	222
7 GOI Share																	
a. GOI Equity share	37.5%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2,500	83
b. GOI share from FTP	100%	572	740	573	721	866	706	606	542	516	500	525	495	267	333	15,716	524
c. Domestic Requirement		670	867	671	845	1,015	827	710	635	605	586	615	581	313	390	14,745	491
d. Gov.Tax Entitlement	44%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,688	56
e. Total GOI Share		1,242	1,607	1,244	1,566	1,881	1,533	1,315	1,177	1,121	1,086	1,140	1,076	580	723	34,649	1,155

Appendix B1

Case A.base case: Cash flow simulation of small (marginal) oil field using IP5 figures

000USD

		%	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
8	Contractor Share																	
a.	Contractor Equity Share	62.5%	0	0	0	0	0	0	0	0	0	0	1,422	2,297	448	0	0	0
b.	Contractor Share from FTP	0%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
c.	DMO first 5 prod.year	25%	0	0	0	0	0	0	0	0	0	0	997	1,066	848	679	868	957
	after 5 prod-years	25%																
d.	Taxable Share		0	0	0	0	0	0	0	0	0	0	979	2,118	738	0	0	0
e	Gov.Tax Entitlement	44%	0	0	0	0	0	0	0	0	0	0	431	932	325	0	0	0
f.	Net Profit Contractor		0	0	0	0	0	0	0	0	0	0	(5)	299	(725)	(679)	(868)	(957)
g	Total Contractor Share		0	932	908	1,281	4,792	3,992	3,937	4,038	3,531	4,796	5,373	4,813	5,068	4,536	5,801	6,395
9	Party's Take																	
a	% GOI Take			10%	10%	10%	10%	10%	10%	10%	10%	10%	37%	47%	30%	22%	22%	22%
b	% Contractor Take			90%	90%	90%	90%	90%	90%	90%	90%	90%	63%	53%	70%	78%	78%	78%
10	Contractor Cash flow																	
a	Net Cash flow		(2,499)	(1,928)	(1,908)	(1,584)	2,165	1,338	1,837	2,254	927	1,735	2,945	920	73	(442)	(783)	1,145
b	NPV @15%		(2,173)	(3,631)	(4,885)	(5,791)	(4,715)	(4,136)	(3,446)	(2,709)	(2,446)	(2,017)	(1,384)	(1,212)	(1,200)	(1,262)	(1,359)	(1,236)
c	NPV @15%/B			(6.64)	(4.57)	(3.76)	(2.28)	(1.65)	(1.18)	(0.82)	(0.67)	(0.51)	(0.32)	(0.27)	(0.25)	(0.25)	(0.26)	(0.22)
d.	IRR																	
e	POT										8							

Appendix B1

Case A.base case: Cash flow simulation of small (marginal) oil field using IP5 figures

000USD

			%	17	18	19	20	21	22	23	24	25	26	27	28	29	30	Total	Mean
8	Contractor Share																		
	a.	Contractor Equity Share	62.5%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4,167	139
	b.	Contractor Share from FTP	0%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	c.	DMO first 5 prod.year	25%	670	867	671	845	1,015	827	710	635	605	586	615	581	313	390	14,745	491
		after 5 prod-years	25%																
	d.	Taxable Share		0	0	0	0	0	0	0	0	0	0	0	0	0	0	3,835	128
	e	Gov.Tax Entitlement	44%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,688	56
	f.	Net Profit Contractor		(670)	(867)	(671)	(845)	(1,015)	(827)	(710)	(635)	(605)	(586)	(615)	(581)	(313)	(390)	(12,265)	(409)
	g	Total Contractor Share		4,477	5,792	4,483	5,643	6,779	5,524	4,740	4,240	4,042	3,916	4,109	3,878	2,090	2,608	122,512	4,084
9	Party's Take																		
	a	% GOI Take		22%	22%	22%	22%	22%	22%	22%	22%	22%	22%	22%	22%	22%	22%	22%	20%
	b	% Contractor Take		78%	78%	78%	78%	78%	78%	78%	78%	78%	78%	78%	78%	78%	78%	78%	80%
10	Contractor Cash flow																		
	a	Net Cash flow		(850)	2,049	(1,358)	367	714	(1,851)	(1,660)	(1,513)	(1,394)	384	(365)	(116)	(526)	(271)	(196)	(7)
	b	NPV @15%		(1,315)	(1,150)	(1,245)	(1,223)	(1,185)	(1,270)	(1,337)	(1,390)	(1,432)	(1,422)	(1,430)	(1,433)	(1,442)	(1,446)	(1,446)	
	c	NPV @15%/B		(0.22)	(0.18)	(0.18)	(0.17)	(0.15)	(0.16)	(0.16)	(0.16)	(0.15)	(0.15)	(0.14)	(0.14)	(0.14)	(0.14)	(0.14)	
	d.	IRR			11%	10%	10%	11%	10%	9%	9%	8%	8%	8%	8%	7%	7%	7%	
	e	POT																8	

Appendix B2

Case B1 base case: Cash flow simulation of medium oil field using IP5 figures

000USD

B1. base case	%	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
1 Annual Expenditures (000 USD)																	
a. Capital Expenditures	22.3%	300	753	1,176	515	1,268	1,999	1,160	1,017	16	(2)	231	282	2,142	5,899	3,774	21,166
b. Non Capital & operating expenditures		1,047	2,622	4,097	1,794	4,416	6,960	4,038	3,543	57	(7)	806	982	7,459	20,545	13,145	73,714
c. Total Expenditures		1,347	3,375	5,273	2,309	5,684	8,959	5,198	4,560	73	(9)	1,037	1,264	9,601	26,444	16,919	94,880
2 Lifting																	
a. Oil (000 BL)																	
b. Oil Prices (USD/B)																	
c. Gas (000 CFT)																	
d. Gas Price(USD/CFT)																	
e. Oil/day																	
3 Gross Revenues before FTP		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
a. FTP	10%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4 Gross Revenue after FTP		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5 Cost Recovery																	
a. Unrecovered cost		0	(1,047)	(3,669)	(7,765)	(9,559)	(13,975)	(20,936)	(24,974)	(28,517)	(28,574)	(28,567)	(29,372)	(30,354)	(37,813)	(58,358)	(71,503)
b. Current Year Operating Cost		1,047	2,622	4,097	1,794	4,416	6,960	4,038	3,543	57	(7)	806	982	7,459	20,545	13,145	73,714
c. Current Depreciation	5ys DDBL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
d. Total Cost Recovery		1,047	3,669	7,765	9,559	13,975	20,936	24,974	28,517	28,574	28,567	29,372	30,354	37,813	58,358	71,503	145,217
e. Current Investment Credit	15.78%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
f. Total Recoverable		1,047	3,669	7,765	9,559	13,975	20,936	24,974	28,517	28,574	28,567	29,372	30,354	37,813	58,358	71,503	145,217
g. Current Maximum cost recovery		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
h. Actual cost recoverable:		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6 Equity to be split		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7 GOI Share																	
a. GOI Equity share	64.28%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
b. GOI share from FTP	100%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
c. Domestic Requirement		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
d. Gov.Tax Entitlement	44%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
e. Total GOI Share		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Appendix B2

Case B1 base case: Cash flow simulation of medium oil field using IP5 figures

000USD

B1. base case	%	17	18	19	20	21	22	23	24	25	26	27	28	29	30	Total	Mean
1 Annual Expenditures (000 USD)																	
a. Capital Expenditures	22.3%	22,269	17,099	25,727	17,797	18,297	25,290	29,184	25,719	20,543	20,919	11,776	8,998	10,438	13,601	309,353	10,312
b. Non Capital & operating expenditures		77,554	59,548	89,598	61,982	63,724	88,078	101,640	89,571	71,543	72,853	41,012	31,336	36,353	47,366	1,077,376	35,913
c. Total Expenditures		99,823	76,647	115,325	79,779	82,021	113,368	130,824	115,290	92,086	93,772	52,788	40,334	46,791	60,967	1,386,729	46,224
2 Lifting																	
a. Oil (000 BL)		4,855	12,732	9,446	14,124	15,721	21,158	16,589	18,129	13,250	10,768	10,137	8,060	7,294	6,545	168,808	12,058
b. Oil Prices (USD/B)		27.69	27.10	14.48	17.68	17.32	17.71	22.57	19.93	19.10	17.68	16.20	17.35	20.41	19.02	19.59	19.59
c. Gas (000 CFT)		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
d. Gas Price(USD/CFT)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
e. Oil/day		13.301	34.882	25.879	38.696	43.071	57.967	45.449	49.668	36.301	29.501	27.773	22.082	19.984	17.932	33.035	33.035
3 Gross Revenues before FTP		134,428	344,979	136,809	249,679	272,296	374,792	374,378	361,310	253,013	190,327	164,228	139,819	148,899	124,457	3,269,414	108,980
a. FTP	10%	13,443	34,498	13,681	24,968	27,230	37,479	37,438	36,131	25,301	19,033	16,423	13,982	14,890	12,446	326,941	10,898
4 Gross Revenue after FTP		120,985	310,481	123,128	224,711	245,066	337,313	336,940	325,179	227,712	171,294	147,805	125,837	134,009	112,011	2,942,473	98,082
5 Cost Recovery																	
a. Unrecovered cost		(145,217)	(127,871)	0	0	0	0	0	0	0	0	0	0	0	0		
b. Current Year Operating Cost		77,554	59,548	89,598	61,982	63,724	88,078	101,640	89,571	71,543	72,853	41,012	31,336	36,353	47,366	1,077,376	35,913
c. Current Depreciation	5ys DDBL	15,991	16,268	18,631	18,426	33,571	20,380	24,628	23,019	22,519	23,778	21,702	17,703	14,659	38,077	309,353	10,312
d. Total Cost Recovery		238,763	203,688	108,229	80,407	97,295	108,457	126,268	112,590	94,062	96,632	62,714	49,040	51,012	85,444	2,054,800	68,493
e. Current Investment Credit	15.78%	10,094	2,698	4,060	2,808	2,887	3,991	4,605	4,058	3,242	3,301	1,858	1,420	1,647	2,146	48,816	1,627
f. Total Recoverable		248,857	206,386	112,289	83,216	100,182	112,448	130,873	116,648	97,304	99,933	64,572	50,459	52,659	87,590	2,103,616	70,121
g. Current Maximum cost recovery		120,985	310,481	123,128	224,711	245,066	337,313	336,940	325,179	227,712	171,294	147,805	125,837	134,009	112,011	2,942,473	98,082
h. Actual cost recoverable:		120,985	206,386	112,289	83,216	100,182	112,448	130,873	116,648	97,304	99,933	64,572	50,459	52,659	87,590	1,435,545	47,851
6 Equity to be split		0	104,095	10,839	141,495	144,884	224,865	206,067	208,531	130,408	71,362	83,233	75,378	81,350	24,421	1,506,928	50,231
7 GOI Share																	
a. GOI Equity share	64.28%	0	66,918	6,968	90,961	93,140	144,556	132,472	134,055	83,834	45,875	53,507	48,457	52,297	15,699	968,739	32,291
b. GOI share from FTP	100%	13,443	34,498	13,681	24,968	27,230	37,479	37,438	36,131	25,301	19,033	16,423	13,982	14,890	12,446	326,941	10,898
c. Domestic Requirement		0	0	0	0	0	28,444	28,413	27,421	19,202	14,444	12,464	10,611	11,300	9,445	161,745	5,391
d. Gov.Tax Entitlement	44%	0	17,545	3,490	23,471	24,038	24,576	21,907	22,490	13,470	6,311	8,413	7,801	8,536	626	182,673	6,089
e. Total GOI Share		13,443	118,961	24,138	139,400	144,407	235,055	220,229	220,097	141,807	85,663	90,807	80,851	87,023	38,216	1,640,098	54,670

Appendix B2

Case B1 base case: Cash flow simulation of medium oil field using IP5 figures

000USD

	%	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
8 Contractor Share																	
a. Contractor Equity Share	35.71%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
b. Contractor Share from FTP	0%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
c. DMO first 5 prod.year	25%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
after 5 prod-years	15%																
d.. Taxable Share		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
e. Gov.Tax Entitlement	44%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
f. Net Profit Contractor		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
g Total Contractor Share		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9 Party's Take																	
a % GOI Take																	
b % Contractor Take																	
10 Contractor Cash flow																	
a. Net Cash flow		(1,347)	(3,375)	(5,273)	(2,309)	(5,684)	(8,959)	(5,198)	(4,560)	(73)	9	(1,037)	(1,264)	(9,601)	(26,444)	(16,919)	(94,880)
b. NPV @15%		(1,171)	(3,723)	(7,190)	(8,511)	(11,337)	(15,210)	(17,164)	(18,655)	(18,675)	(18,673)	(18,896)	(19,132)	(20,693)	(24,430)	(26,509)	(36,648)
c. NPV @15% /B																	
d. IRR																	
e. POT																	

Appendix B2

Case B1 base case: Cash flow simulation of medium oil field using IP5 figures

000USD

	17	18	19	20	21	22	23	24	25	26	27	28	29	30	Total	Mean
8 Contractor Share																
a. Contractor Equity Share	0	37,177	3,871	50,534	51,744	80,309	73,595	74,475	46,574	25,486	29,726	26,921	29,054	8,722	538,189	17,940
b. Contractor Share from FTP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
c. DMO first 5 prod.year	0	0	0	0	0	28,444	28,413	27,421	19,202	14,444	12,464	10,611	11,300	9,445	161,745	5,391
after 5 prod-years																
d.. Taxable Share	0	39,875	7,931	53,342	54,632	55,856	49,788	51,113	30,614	14,343	19,121	17,729	19,400	1,423	415,166	13,839
e. Gov.Tax Entitlement	0	17,545	3,490	23,471	24,038	24,576	21,907	22,490	13,470	6,311	8,413	7,801	8,536	626	182,673	6,089
f. Net Profit Contractor	0	19,632	382	27,063	27,706	27,288	23,276	24,565	13,902	4,731	8,849	8,508	9,217	(1,349)	193,771	6,459
g Total Contractor Share	120,985	226,018	112,671	110,279	127,889	139,737	154,149	141,213	111,206	104,664	73,421	58,968	61,876	86,241	1,629,316	54,311
9 Party's Take																
a % GOI Take	10%	34%	18%	56%	53%	63%	59%	61%	56%	45%	55%	58%	58%	31%	50%	47%
b % Contractor Take	90%	66%	82%	44%	47%	37%	41%	39%	44%	55%	45%	42%	42%	69%	50%	53%
10 Contractor Cash flow																
a. Net Cash flow	21,162	149,371	(2,654)	30,500	45,868	26,369	23,325	25,923	19,120	10,892	20,633	18,634	15,085	25,274	242,587	8,086
b. NPV @15%	(34,682)	(22,612)	(22,799)	(20,935)	(18,498)	(17,280)	(16,343)	(15,437)	(14,856)	(14,569)	(14,095)	(13,722)	(13,460)	(13,079)	(13,079)	
c. NPV @15% /B	(7.14)	(1.29)	(0.84)	(0.51)	(0.33)	(0.22)	(0.17)	(0.14)	(0.12)	(0.11)	(0.10)	(0.09)	(0.08)	(0.08)	(0.08)	
d. IRR		-2%	#DIV/0!	1%	5%	6%	7%	8%	8%	9%	9%	9%	10%	10%	10%	
e. POT				19											19	

Appendix B3

Case B2.base case: Cash flow simulation of large oil field using IP5 figures

000USD

	%	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
1 Annual Expenditures (000 USD)																	
a. Capital Expenditures	22.3%	102	235	3,195	5,617	6,403	15,283	14,308	24,189	27,043	15,474	18,484	24,079	41,594	92,770	134,100	85,136
b. Non Capital & operating expenditures		357	817	11,128	19,561	22,300	53,225	49,828	84,241	94,182	53,889	64,375	83,857	144,857	323,089	467,026	296,500
c. Total Expenditures		459	1,052	14,323	25,178	28,703	68,508	64,136	108,430	121,225	69,363	82,859	107,936	186,451	415,859	601,126	381,636
2 Lifting					1	2	3	4	5	6	7	8	9	10	11	12	13
a. Oil (000 BL)					3,408	13,369	13,640	19,787	15,434	34,334	41,473	30,774	32,731	30,079	40,884	40,458	36,419
b. Oil Prices (USD/B)					1.76	2.82	4.05	11.42	13.14	12.45	12.98	13.13	18.00	29.66	34.14	33.49	28.71
c. Gas (000 CFT)											0	0	0	0	0	0	0
d Gas Price(USD/CFT)											0	0	0	0	0	0	0
e Oil/day					9	37	37	54	42	94	114	84	90	82	112	111	100
3 Gross Revenues before FTP					5,982	37,738	55,262	226,035	202,841	427,565	538,343	404,168	589,260	892,015	1,395,743	1,354,757	1,045,478
a. FTP	10%	0	0	0	598	3,774	5,526	22,604	20,284	42,757	53,834	40,417	58,926	89,202	139,574	135,476	104,548
4 Gross Revenue after FTP		0	0	0	5,384	33,964	49,736	203,432	182,557	384,809	484,509	363,751	530,334	802,814	1,256,169	1,219,281	940,930
5 Cost Recovery																	
a. Unrecovered cost		0	(357)	(1,174)	(12,302)	(29,653)	(22,315)	(34,524)	0	0	0	0	0	0	0	0	0
b. Current Year Operating Cost		357	817	11,128	19,561	22,300	53,225	49,828	84,241	94,182	53,889	64,375	83,857	144,857	323,089	467,026	296,500
c. Current Depreciation	5ys DDBL	0	0	0	2,287	3,316	6,308	8,308	14,449	16,946	18,685	18,403	22,167	27,701	41,223	65,156	71,478
d. Total Cost Recovery		357	1,174	12,302	34,150	55,269	81,848	92,660	98,690	111,128	72,574	82,778	106,025	172,558	364,311	532,182	367,978
e. Current Investment Credit	15.78%	0	0	0	886	1,010	2,412	2,258	3,817	4,267	2,442	2,917	3,800	6,563	14,639	21,161	13,434
f. Total Recoverable		357	1,174	12,302	35,037	56,279	84,260	94,918	102,507	115,395	75,016	85,695	109,824	179,122	378,951	553,343	381,412
g. Current Maximum cost recovery		0	0	0	5,384	33,964	49,736	203,432	182,557	384,809	484,509	363,751	530,334	802,814	1,256,169	1,219,281	940,930
h. Actual cost recoverable		0	0	0	5,384	33,964	49,736	94,918	102,507	115,395	75,016	85,695	109,824	179,122	378,951	553,343	381,412
6 Equity to be split		0	0	0	0	0	0	108,514	80,050	269,413	409,493	278,056	420,510	623,692	877,218	665,938	559,518
7 GOI Share																	
a. GOI Equity share	64.28%	0	0	0	0	0	0	69,759	51,461	173,194	263,245	178,750	270,328	400,945	563,926	428,103	359,690
b. GOI share from FTP	100%	0	0	0	598	3,774	5,526	22,604	20,284	42,757	53,834	40,417	58,926	89,202	139,574	135,476	104,548
c. Domestic Requirement		0	0	0	0	0	0	0	0	32,449	40,856	30,673	44,721	67,698	105,927	102,816	79,344
d. Gov.Tax Entitlement	44%	0	0	0	0	0	0	18,046	14,259	29,936	47,446	31,482	48,075	71,110	97,682	68,719	58,924
e. Total GOI Share		0	0	0	598	3,774	5,526	110,408	86,003	278,336	405,382	281,322	422,049	628,953	907,109	735,114	602,506

Appendix B3

Case B2.base case: Cash flow simulation of large oil field using IP5 figures

000USD

	17	18	19	20	21	22	23	24	25	26	27	28	29	30	Total	Mean
1 Annual Expenditures (000 USD)																
a. Capital Expenditures	52,386	35,284	25,871	15,414	18,203	31,088	78,534	53,642	49,181	56,726	53,749	56,379	56,042	66,968	1,157,478	38,583
b. Non Capital & operating expenditures	182,444	122,884	90,098	53,683	63,393	108,268	273,510	186,818	171,281	197,556	187,188	196,350	195,178	233,228	4,031,112	134,370
c. Total Expenditures	234,830	158,168	115,969	69,097	81,596	139,356	352,044	240,460	220,462	254,282	240,937	252,729	251,220	300,196	5,188,590	172,953
2 Lifting	14	15	16	17	18	19	20	21	22	23	24	25	26	27		
a. Oil (000 BL)	32,753	28,768	29,453	21,897	20,258	25,408	31,676	75,251	62,896	51,935	55,334	50,358	50,867	50,782	940,426	34,831
b. Oil Prices (USD/B)	28.32	27.17	14.34	16.72	16.51	17.21	22.16	19.37	17.88	16.72	15.27	16.77	19.78	18.14	17.86	17.86
c. Gas (000 CFT)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
d Gas Price(USD/CFT)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
e Oil/day	90	79	81	60	56	70	87	206	172	142	152	138	139	139	95	95
3 Gross Revenues before FTP	927,542	781,683	422,239	366,177	334,433	437,278	701,912	1,457,582	1,124,763	868,492	844,843	844,734	1,006,314	921,345	18,214,524	674,612
a. FTP	92,754	78,168	42,224	36,618	33,443	43,728	70,191	145,758	112,476	86,849	84,484	84,473	100,631	92,135	1,821,452	60,715
4 Gross Revenue after FTP	834,788	703,515	380,015	329,559	300,990	393,550	631,721	1,311,824	1,012,287	781,643	760,359	760,261	905,683	829,211	16,393,072	546,436
5 Cost Recovery																
a. Unrecovered cost	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
b. Current Year Operating Cost	182,444	122,884	90,098	53,683	63,393	108,268	273,510	186,818	171,281	197,556	187,188	196,350	195,178	233,228	4,031,112	134,370
c. Current Depreciation	70,862	74,114	71,860	46,129	31,376	27,245	37,833	39,304	42,434	49,066	61,496	54,309	53,684	181,338	1,157,478	38,583
d. Total Cost Recovery	253,305	196,997	161,958	99,812	94,769	135,514	311,343	226,122	213,715	246,623	248,684	250,659	248,862	414,566	5,288,914	176,297
e. Current Investment Credit	8,267	5,568	4,082	2,432	2,872	4,906	12,393	8,465	7,761	8,951	8,482	8,897	8,844	10,568	182,093	6,070
f. Total Recoverable	261,572	202,565	166,041	102,244	97,642	140,419	323,736	234,587	221,476	255,574	257,166	259,556	257,705	425,133	5,471,006	182,367
g. Current Maximum cost recovery	834,788	703,515	380,015	329,559	300,990	393,550	631,721	1,311,824	1,012,287	781,643	760,359	760,261	905,683	829,211	16,393,072	546,436
h. Actual cost recoverable	261,572	202,565	166,041	102,244	97,642	140,419	323,736	234,587	221,476	255,574	257,166	259,556	257,705	425,133	5,370,683	179,023
6 Equity to be split	573,216	500,949	213,974	227,315	203,348	253,131	307,985	1,077,237	790,811	526,069	503,193	500,705	647,977	404,077	11,022,389	367,413
7 GOI Share																
a. GOI Equity share	368,496	322,039	137,555	146,131	130,724	162,727	197,990	692,509	508,378	338,187	323,481	321,882	416,557	259,764	7,085,820	236,194
b. GOI share from FTP	92,754	78,168	42,224	36,618	33,443	43,728	70,191	145,758	112,476	86,849	84,484	84,473	100,631	92,135	1,821,452	60,715
c. Domestic Requirement	70,394	59,324	32,045	27,790	25,381	33,186	53,270	110,620	85,362	65,912	64,118	64,109	76,372	69,924	1,342,292	44,743
d. Gov.Tax Entitlement	62,741	55,068	21,321	24,564	22,051	27,334	30,412	124,332	90,126	57,605	54,593	54,389	72,112	37,381	1,219,707	40,657
e. Total GOI Share	594,385	514,599	233,145	235,103	211,599	266,975	351,863	1,073,220	796,342	548,554	526,676	524,853	665,673	459,203	11,469,271	382,309

Appendix B3

Case B2.base case: Cash flow simulation of large oil field using IP5 figures

000USD

	%	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
8 Contractor Share																	
a. Contractor Equity Share	35.71%	0	0	0	0	0	0	38,755	28,589	96,219	146,247	99,306	150,182	222,747	313,292	237,835	199,828
b. Contractor Share from FTP	0%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
c. DMO first 5 prod.year	25%	0	0	0	0	0	0	0	0	32,449	40,856	30,673	44,721	67,698	105,927	102,816	79,344
after 5 prod-years	15%																
e. Taxable Share		0	0	0	0	0	0	41,013	32,406	68,037	107,833	71,549	109,261	161,613	222,005	156,180	133,918
f. Gov.Tax Entitlement	44%	0	0	0	0	0	0	18,046	14,259	29,936	47,446	31,482	48,075	71,110	97,682	68,719	58,924
g Net Profit Contractor		0	0	0	0	0	0	20,709	14,330	33,833	57,945	37,151	57,387	83,940	109,683	66,300	61,560
I. Total Contractor Share		0	0	0	5,384	33,964	49,736	115,627	116,838	149,229	132,961	122,846	167,211	263,062	488,634	619,643	442,972
9 Party's Take																	
a % GOI Take					10%	10%	10%	49%	42%	65%	75%	70%	72%	71%	65%	54%	58%
b % Contractor Take					90%	90%	90%	51%	58%	35%	25%	30%	28%	29%	35%	46%	42%
10 Contractor Cash flowanalysis																	
a. Net Cash flow		(459)	(1,052)	(14,323)	(19,794)	5,261	(18,772)	51,491	8,408	28,004	63,598	39,987	59,275	76,611	72,775	18,517	61,336
b. NPV @15%		(399)	(1,195)	(10,612)	(21,930)	(19,314)	(27,430)	(8,072)	(5,324)	2,637	18,357	26,952	38,031	50,482	60,767	63,043	69,598
c. NPV @15% /B												0.16	0.19	0.21	0.22	0.20	0.20
d. IRR														38%	40%	40%	41%
e. POT								6									

Appendix B3

Case B2.base case: Cash flow simulation of large oil field using IP5 figures

000USD

		17	18	19	20	21	22	23	24	25	26	27	28	29	30	Total	Mean
8	Contractor Share																
a.	Contractor Equity Share	204,720	178,911	76,419	81,184	72,624	90,404	109,995	384,728	282,433	187,882	179,712	178,823	231,421	144,313	3,936,569	131,219
b.	Contractor Share from FTP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
c.	DMO first 5 prod.year	70,394	59,324	32,045	27,790	25,381	33,186	53,270	110,620	85,362	65,912	64,118	64,109	76,372	69,924	1,342,292	44,743
	after 5 prod-years																
e.	Taxable Share	142,593	125,154	48,457	55,826	50,116	62,123	69,117	282,572	204,832	130,921	124,076	123,611	163,892	84,957	2,772,061	92,402
f.	Gov.Tax Entitlement	62,741	55,068	21,321	24,564	22,051	27,334	30,412	124,332	90,126	57,605	54,593	54,389	72,112	37,381	1,219,707	40,657
g	Net Profit Contractor	71,585	64,519	23,053	28,830	25,192	29,883	26,313	149,776	106,945	64,364	61,001	60,325	82,936	37,009	1,374,570	45,819
I.	Total Contractor Share	333,157	267,084	189,094	131,074	122,834	170,303	350,049	384,362	328,421	319,938	318,167	319,881	340,641	462,142	6,745,253	224,842
9	Party's Take																
a	% GOI Take	64%	66%	55%	64%	63%	61%	50%	74%	71%	63%	62%	62%	66%	50%	63%	56%
b	% Contractor Take	36%	34%	45%	36%	37%	39%	50%	26%	29%	37%	38%	38%	34%	50%	37%	44%
10	Contractor Cash flowanalysis																
a.	Net Cash flow	98,327	108,916	73,125	61,977	41,238	30,947	(1,995)	143,902	107,959	65,656	77,230	67,152	89,421	161,946	1,556,663	51,889
b.	NPV @15%	78,735	87,536	92,674	96,461	98,652	100,082	100,001	105,029	108,308	110,042	111,816	113,158	114,711	117,157	117,157	
c.	NPV @15% /B	0.20	0.21	0.21	0.21	0.20	0.20	0.18	0.17	0.16	0.15	0.14	0.13	0.13	0.12	0.12	
d.	IRR	41%	42%	42%	42%	42%	42%	42%	42%	42%	42%	42%	42%	42%	42%	42%	
e.	POT															6	

Appendix B4

Case C1 base case: Cash flow simulation of medium oil and gas field using IP5 figures

000USD

	%	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
1 Annual Expenditures (000 USD)																	
a. Capital Expenditures	22.3%	1	167	722	4,089	11,599	16,465	16,295	10,999	8,263	9,302	11,094	14,519	17,917	15,491	15,967	16,246
b. Non Capital & operating expenditures		2	580	2,514	14,239	40,395	57,344	56,751	38,304	28,779	32,396	38,638	50,565	62,398	53,951	55,606	56,580
c. Total Expenditures		3	747	3,236	18,328	51,994	73,809	73,046	49,303	37,042	41,698	49,732	65,084	80,315	69,442	71,573	72,826
2 Lifting																	
a. Oil (000 BL)					3,413	11,076	22,890	27,301	28,672	25,946	22,662	19,864	16,132	15,715	13,551	11,841	11,342
c. Oil Prices (USD/B)					5.69	10.61	10.61	11.99	12.90	13.10	18.21	29.98	34.93	34.01	29.60	32.55	28.28
d. Gas (000 CFT)																	
e. Gas Price(USD/CFT)																	
f Prod oil& gas (000BOE)					3,413	11,076	22,890	27,301	28,672	25,946	22,662	19,864	16,132	15,715	13,551	11,841	11,342
g Prod gas (000BOE)																	
h Cum Oil & gas (000 BOE)					3,413	14,489	37,379	64,680	93,352	119,298	141,960	161,824	177,956	193,671	207,222	219,063	230,405
Oil & gas /day (000BOE)					9	30	63	75	79	71	62	54	44	43	37	32	31
3 Gross Revenue before FTP																	
a Gross Revenues oil					19,405	117,480	242,975	327,447	369,847	340,003	412,588	595,523	563,443	534,438	401,150	385,450	320,706
b Gross Revenues gas											0	0	0	0	0	0	0
c Gross Revenues oil&gas (000 USD)					19,405	117,480	242,975	327,447	369,847	340,003	412,588	595,523	563,443	534,438	401,150	385,450	320,706
4 FTP																	
a FTP oil	10%				1,941	11,748	24,298	32,745	36,985	34,000	41,259	59,552	56,344	53,444	40,115	38,545	32,071
b FTP gas											0	0	0	0	0	0	0
c FTP oil & gas					1,941	11,748	24,298	32,745	36,985	34,000	41,259	59,552	56,344	53,444	40,115	38,545	32,071
5 Gross Revenue after FTP																	
a Gross Revenue oil after FTP					17,465	105,732	218,678	294,702	332,862	306,003	371,329	535,971	507,099	480,994	361,035	346,905	288,635
b Gross Revenue gas after FTP											0	0	0	0	0	0	0
c Gross Revenue oil & gas after FTP					17,465	105,732	218,678	294,702	332,862	306,003	371,329	535,971	507,099	480,994	361,035	346,905	288,635
6 Cost Recovery oil & gas																	
a. Unrecovered cost		0	(2)	(583)	(3,097)	(1,902)	0	0	0	0	0	0	0	0	0	0	0
b. Current Year Operating Cost		2	580	2,514	14,239	40,395	57,344	56,751	38,304	28,779	32,396	38,638	50,565	62,398	53,951	55,606	56,580
c. Current Depreciation	5ys DDBL	0	0	0	1,244	3,833	6,991	9,317	10,919	11,826	12,350	11,996	11,370	12,357	13,387	14,457	15,717
d. Total Cost Recovery		2	583	3,097	18,581	46,130	64,335	66,068	49,223	40,605	44,746	50,633	61,935	74,755	67,338	70,064	72,297
e. Current Investment Credit	15.78%	0	0	0	786	1,830	2,598	2,571	1,736	1,304	1,468	1,751	2,291	2,827	2,445	2,520	2,564
f. Total Recoverable		2	583	3,097	19,366	47,960	66,933	68,639	50,959	41,909	46,214	52,384	64,226	77,583	69,782	72,583	74,861
g. Current Maximum cost recovery		0	0	0	17,465	105,732	218,678	294,702	332,862	306,003	371,329	535,971	507,099	480,994	361,035	346,905	288,635
h. Actual cost recoverable		0	0	0	17,465	47,960	66,933	68,639	50,959	41,909	46,214	52,384	64,226	77,583	69,782	72,583	74,861

Appendix B4

Case C1 base case: Cash flow simulation of medium oil and gas field using IP5 figures

000USD

	17	18	19	20	21	22	23	24	25	26	27	28	29	30	Total	Mean
1 Annual Expenditures (000 USD)																
a. Capital Expenditures	13,902	11,082	12,312	10,791	12,143	14,497	11,337	10,445	9,251	8,467	6,713	7,178	3,455	4,785	305,492	10,183
b. Non Capital & operating expenditures	48,414	38,594	42,879	37,582	42,288	50,487	39,481	36,375	32,220	29,486	23,379	25,000	12,034	16,663	1,063,926	35,464
c. Total Expenditures	62,316	49,676	55,191	48,373	54,431	64,984	50,818	46,820	41,471	37,953	30,092	32,178	15,489	21,448	1,369,418	45,647
2 Lifting																
a. Oil (000 BL)	10,150	9,954	7,979	7,363	6,519	5,920	5,774	5,017	4,904	4,216	3,776	3,673	3,540	2,924	312,114	11,560
c. Oil Prices (USD/B)	12.72	17.58	16.78	17.55	21.93	19.23	18.89	17.21	15.98	17.05	20.18	19.04	12.10	17.20	19.11	19.11
d. Gas (000 CFT)						243	679	845	737	764	751	714	620	307	5,660	629
e. Gas Price (USD/CFT)						2.27	2.04	1.70	1.76	1.80	2.04	2.22	1.96	3.88	2.18	2.18
f Prod oil& gas (000BOE)	10,150	9,954	7,979	7,363	6,519	5,973	5,922	5,201	5,064	4,382	3,939	3,828	3,675	2,991	313,344	11,605
g Prod gas (000BOE)						53	148	184	160	166	163	155	135	67	1,230	137
h Cum Oil & gas (000 BOE)	240,555	250,509	258,488	265,851	272,370	278,343	284,264	289,465	294,529	298,911	302,851	306,679	310,354	313,344	313,344	
Oil & gas /day (000BOE)	28	27	22	20	18	16	16	14	14	12	11	10	10	8	32	32
3 Gross Revenue before FTP																
a Gross Revenues oil	129,147	175,019	133,905	129,225	142,934	113,846	109,054	86,330	78,350	71,878	76,195	69,929	42,839	50,296	6,039,402	223,682
b Gross Revenues gas	0	0	0	0	0	552	1,384	1,438	1,295	1,374	1,529	1,582	1,216	1,191	11,561	551
c Gross Revenues oil&gas (000 USD)	129,147	175,019	133,905	129,225	142,934	114,398	110,438	87,768	79,645	73,252	77,724	71,511	44,055	51,487	6,050,963	224,110
4 FTP																
a FTP oil	12,915	17,502	13,391	12,923	14,293	11,385	10,905	8,633	7,835	7,188	7,620	6,993	4,284	5,030	603,940	22,368
b FTP gas	0	0	0	0	0	55	138	144	130	137	153	158	122	119	1,156	55
c FTP oil & gas	12,915	17,502	13,391	12,923	14,293	11,440	11,044	8,777	7,965	7,325	7,772	7,151	4,406	5,149	605,096	22,411
5 Gross Revenue after FTP																
a Gross Revenue oil after FTP	116,232	157,517	120,515	116,303	128,641	102,461	98,149	77,697	70,515	64,690	68,576	62,936	38,555	45,266	5,435,462	201,313
b Gross Revenue gas after FTP	0	0	0	0	0	497	1,246	1,294	1,166	1,237	1,376	1,424	1,094	1,072	10,405	495
c Gross Revenue oil & gas after FTP	116,232	157,517	120,515	116,303	128,641	102,958	99,394	78,991	71,681	65,927	69,952	64,360	39,650	46,338	5,445,867	201,699
6 Cost Recovery oil & gas																
a. Unrecovered cost	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
b. Current Year Operating Cost	48,414	38,594	42,879	37,582	42,288	50,487	39,481	36,375	32,220	29,486	23,379	25,000	12,034	16,663	1,063,926	35,464
c. Current Depreciation	16,070	14,247	13,876	13,171	12,358	12,223	12,294	11,470	11,236	11,103	9,255	8,524	6,974	16,925	305,492	10,183
d. Total Cost Recovery	64,484	52,841	56,755	50,753	54,646	62,711	51,775	47,846	43,456	40,589	32,634	33,524	19,008	33,588	1,375,001	45,833
e. Current Investment Credit	2,194	1,749	1,943	1,703	1,916	2,288	1,789	1,648	1,460	1,336	1,059	1,133	545	755	48,207	1,607
f. Total Recoverable	66,678	54,590	58,698	52,456	56,562	64,998	53,564	49,494	44,916	41,925	33,694	34,657	19,553	34,343	1,423,208	47,440
g. Current Maximum cost recovery	116,232	157,517	120,515	116,303	128,641	102,958	99,394	78,991	71,681	65,927	69,952	64,360	39,650	46,338	5,445,867	181,529
h. Actual cost recoverable	66,678	54,590	58,698	52,456	56,562	64,998	53,564	49,494	44,916	41,925	33,694	34,657	19,553	34,343	1,417,625	47,254

Appendix B4.

Case C1 base case: Cash flow simulation of medium oil and gas field using IP5 figures

000USD

	%	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
7 Equity to be split																	
a Equity to be split oil & gas		0	0	0	0	57,772	151,745	226,063	281,904	264,094	325,115	483,587	442,873	403,411	291,253	274,322	213,775
b Equity to be split oil		0	0	0	0	57,772	151,745	226,063	281,904	264,094	325,115	483,587	442,873	403,411	291,253	274,322	213,775
c Equity to be split gas							0	0	0	0	0	0	0	0	0	0	0
8 GOI Share																	
a. GOI Equity share oil	64.28%	0	0	0	0	37,139	97,550	145,326	181,224	169,775	209,003	310,877	284,704	259,336	187,234	176,350	137,426
b. GOI Equity share gas	37.5%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
c GOI share from FTP oil	100%	0	0	0	1,941	11,748	24,298	32,745	36,985	34,000	41,259	59,552	56,344	53,444	40,115	38,545	32,071
d. GOI share from FTP gas	100%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
e. Domestic Requirement					0	0	0	0	0	25,804	31,312	45,196	42,761	40,560	30,444	29,253	24,339
f. Gov.Tax Entitlement	44%				0	9,884	24,989	36,656	45,063	30,721	37,958	56,876	51,787	46,791	33,448	31,345	24,012
g Total GOI Share		0	0	0	1,941	58,771	146,836	214,727	263,271	260,299	319,532	472,502	435,597	400,131	291,241	275,493	217,848
9 Contractor Share																	
a. Contractor Equity Share oil	35.71%	0	0	0	0	20,633	54,195	80,737	100,680	94,319	116,113	172,710	158,169	144,076	104,019	97,972	76,348
b. Contractor Equity Share gas	62.5%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
c Contractor Share from FTP oil	0%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
d. Contractor Share from FTP gas	0%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
e. DMO oil first 5 prod.year	25%	0	0	0	0	0	0	0	0	25,804	31,312	45,196	42,761	40,560	30,444	29,253	24,339
after 5 prod-years	15%																
f. Taxable Share		0	0	0	0	22,463	56,793	83,308	102,415	69,819	86,268	129,264	117,699	106,343	76,019	71,239	54,572
g Gov.Tax Entitlement	44%	0	0	0	0	9,884	24,989	36,656	45,063	30,721	37,958	56,876	51,787	46,791	33,448	31,345	24,012
h Net Profit Contractor		0	0	0	0	10,749	29,206	44,081	55,617	37,795	46,842	70,637	63,620	56,725	40,126	37,374	27,997
1 Total Contractor Share		0	0	0	17,465	58,709	96,139	112,720	106,576	79,704	93,056	123,021	127,846	134,307	109,909	109,957	102,858
10 Party's Take																	
a % GOI Take					10%	50%	60%	66%	71%	77%	77%	79%	77%	75%	73%	71%	68%
b % Contractor Take					90%	50%	40%	34%	29%	23%	23%	21%	23%	25%	27%	29%	32%
11 Contractor Cash analysis																	
a. Net Cash flow Contractor		(3)	(747)	(3,236)	(864)	6,715	22,330	39,674	57,273	42,662	51,358	73,289	62,762	53,992	40,467	38,384	30,032
b. NPV @15%		(3)	(567)	(2,695)	(3,189)	150	9,803	24,719	43,441	55,568	68,263	84,016	95,747	104,522	110,241	114,958	118,168
c NPV @15% /B						0.01	0.26	0.38	0.47	0.47	0.48	0.52	0.54	0.54	0.53	0.52	0.51
d. IRR								119%	131%	134%	136%	136%	137%	137%	137%	137%	137%
e. POT						4											

Appendix B4

Case C1 base case: Cash flow simulation of medium oil and gas field using IP5 figures

000USD

		17	18	19	20	21	22	23	24	25	26	27	28	29	30	Total	Mean
7	Equity to be split																
a	Equity to be split oil & gas	49,555	102,927	61,817	63,846	72,078	37,960	45,830	29,497	26,765	24,002	36,258	29,703	20,097	11,995	4,028,242	134,275
b	Equity to be split oil	49,555	102,927	61,817	63,846	72,078	37,624	44,688	28,455	25,918	23,092	34,755	28,499	19,359		4,008,527	138,225
c	Equity to be split gas	0	0	0	0	0	336	1,142	1,042	847	910	1,503	1,204	737	11,995	19,716	789
8	GOI Share																
a.	GOI Equity share oil	31,856	66,167	39,739	41,044	46,336	24,187	28,728	18,293	16,661	14,845	22,343	18,321	12,445	0	2,576,909	85,897
b.	GOI Equity share gas	0	0	0	0	0	126	428	391	318	341	564	452	276	4,498	7,393	
c	GOI share from FTP oil	12,915	17,502	13,391	12,923	14,293	11,385	10,905	8,633	7,835	7,188	7,620	6,993	4,284	5,030	603,940	20,131
d.	GOI share from FTP gas	0	0	0	0	0	55	138	144	130	137	153	158	122	119	1,156	
e.	Domestic Requirement	9,801	13,283	10,162	9,807	10,848	8,640	8,276	6,552	5,946	5,455	5,783	5,307	3,251	3,817	376,599	13,948
f.	Gov.Tax Entitlement	4,440	11,099	6,097	6,467	7,397	3,210	4,482	2,600	2,332	2,067	3,797	2,973	2,054	1,951	490,495	18,166
g	Total GOI Share	59,012	108,051	69,390	70,241	78,874	47,602	52,959	36,613	33,221	30,033	40,258	34,203	22,433	15,415	4,056,493	135,216
9	Contractor Share																
a.	Contractor Equity Share oil	17,698	36,760	22,077	22,802	25,742	13,437	15,960	10,163	9,256	8,247	12,413	10,178	6,914	0	1,431,617	47,721
b.	Contractor Equity Share gas	0	0	0	0	0	210	714	651	529	569	939	753	461	7,497		
c	Contractor Share from FTP oil	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
d.	Contractor Share from FTP gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
e.	DMO oil first 5 prod.year	9,801	13,283	10,162	9,807	10,848	8,640	8,276	6,552	5,946	5,455	5,783	5,307	3,251	3,817	376,599	12,553
	after 5 prod-years																
f.	Taxable Share	10,090	25,226	13,858	14,698	16,811	7,295	10,186	5,910	5,299	4,697	8,628	6,756	4,669	4,435	1,114,761	37,159
g	Gov.Tax Entitlement	4,440	11,099	6,097	6,467	7,397	3,210	4,482	2,600	2,332	2,067	3,797	2,973	2,054	1,951	490,495	16,350
h	Net Profit Contractor	3,457	12,378	5,817	6,528	7,498	1,797	3,916	1,662	1,508	1,294	3,773	2,651	2,069	1,728	576,845	19,228
1	Total Contractor Share	70,135	66,968	64,515	58,984	64,060	66,796	57,479	51,155	46,424	43,219	37,466	37,308	21,622	36,072	1,994,470	66,482
10	Party's Take																
a	% GOI Take	46%	62%	52%	54%	55%	42%	48%	42%	42%	41%	52%	48%	51%	30%	67%	56%
b	% Contractor Take	54%	38%	48%	46%	45%	58%	52%	58%	58%	59%	48%	52%	49%	70%	33%	44%
11	Contractor Cash analysis																
a.	Net Cash flow Contractor	7,819	17,292	9,324	10,611	9,629	1,812	6,661	4,335	4,953	5,266	7,374	5,130	6,133	14,624	625,052	20,835
b.	NPV @15%	118,894	120,292	120,947	121,595	122,107	122,190	122,458	122,610	122,760	122,899	123,068	123,171	123,277	123,498	123,498	
c	NPV @15% /B	0.49	0.48	0.47	0.46	0.45	0.44	0.43	0.42	0.42	0.41	0.41	0.40	0.40	0.39	0.39	
d.	IRR	137%	137%	137%	137%	137%	137%	137%	137%	137%	137%	137%	137%	137%	137%	137%	
e.	POT															4	

Appendix B5

Case C2 base case: Cash flow simulation of large oil and gas field using IP5 figures

000USD

	%	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
1 Annual Expenditures (000 USD)																	
a. Capital Expenditures	22.3%	197	1,526	5,286	10,837	9,014	27,065	38,272	20,890	14,726	7,269	8,526	14,096	22,226	29,034	26,670	32,049
b. Non Capital & operating expenditures		688	5,315	18,411	37,742	31,392	94,259	133,290	72,751	51,285	25,315	29,694	49,091	77,408	101,116	92,881	111,614
c. Total Expenditures		885	6,841	23,697	48,579	40,406	121,324	171,562	93,641	66,011	32,584	38,220	63,187	99,634	130,150	119,551	143,663
2 Lifting																	
a. Oil (000 BL)						13,282	18,509	20,959	27,709	29,110	27,067	23,969	22,177	18,216	14,986	12,832	13,147
c. Oil Prices (USD/B)						4.07	12.00	11.72	12.65	13.93	14.66	20.00	32.49	36.67	36.35	29.04	28.68
d. Gas (000 CFT)											1,628	2,690	7,169	6,948	5,223	4,903	12,786
e. Gas Price (USD/CFT)											1.60	2.46	2.65	2.46	2.29	2.73	2.27
f Prod oil& gas (000BOE)						13,282	18,509	20,959	27,709	29,110	27,421	24,554	23,735	19,726	16,121	13,898	15,927
g Prod oil &gas (000BOE)						0	0	0	0	0	354	585	1,558	1,510	1,135	1,066	2,780
h Cum Oil & gas (000 BOE)						13,282	31,791	52,750	80,459	109,569	136,990	161,544	185,279	205,006	221,127	235,025	250,951
3 Gross Revenue before FTP																	
a Gross Revenues oil						54,051	222,092	245,634	350,649	405,638	396,670	479,354	720,607	667,979	544,813	372,580	376,997
b Gross Revenues gas											2,601	6,613	19,002	17,088	11,967	13,367	28,967
c Gross Revenues oil&gas (000 USD)						54,051	222,092	245,634	350,649	405,638	399,271	485,967	739,609	685,067	556,780	385,947	405,964
4 FTP																	
a FTP oil	10%					5,405	22,209	24,563	35,065	40,564	39,667	47,935	72,061	66,798	54,481	37,258	37,700
b FTP gas											260	661	1,900	1,709	1,197	1,337	2,897
c FTP oil & gas						5,405	22,209	24,563	35,065	40,564	39,927	48,597	73,961	68,507	55,678	38,595	40,596
5 Gross Revenue after FTP																	
a Gross Revenue oil after FTP						48,646	199,883	221,071	315,584	365,074	357,003	431,419	648,546	601,181	490,332	335,322	339,297
b Gross Revenue gas after FTP											2,341	5,952	17,102	15,379	10,770	12,030	26,070
c Gross Revenue oil & gas after FTP						48,646	199,883	221,071	315,584	365,074	359,344	437,370	665,648	616,560	501,102	347,352	365,368
6 Cost Recovery oil & gas																	
a. Unrecovered cost:		0	(688)	(6,002)	(24,413)	(62,155)	(55,855)	0	0	0	0	0	0	0	0	0	0
b. Current Year Operating Cost		688	5,315	18,411	37,742	31,392	94,259	133,290	72,751	51,285	25,315	29,694	49,091	77,408	101,116	92,881	111,614
c. Current Depreciation	5ys DDBL	0	0	0	0	6,715	11,803	18,419	19,038	24,333	20,117	19,878	14,308	14,824	16,607	19,421	23,900
d. Total Cost Recovery		688	6,002	24,413	62,155	100,262	161,917	151,709	91,789	75,619	45,432	49,572	63,399	92,232	117,723	112,303	135,514
e. Current Investment Credit	15.78%	0	0	0	0	4,239	4,271	6,039	3,296	2,324	1,147	1,345	2,224	3,507	4,582	4,208	5,057
f. Total Recoverable		688	6,002	24,413	62,155	104,501	166,188	157,748	95,085	77,942	46,579	50,917	65,623	95,739	122,305	116,511	140,571
g. Current Maximum cost recovery		0	0	0	0	48,646	199,883	221,071	315,584	365,074	359,344	437,370	665,648	616,560	501,102	347,352	365,368
h. Actual cost recoverable		0	0	0	0	48,646	166,188	157,748	95,085	77,942	46,579	50,917	65,623	95,739	122,305	116,511	140,571

Appendix B5

Case C2 base case: Cash flow simulation of large oil and gas field using IP5 figures

000USD

	17	18	19	20	21	22	23	24	25	26	27	28	29	30	Total	Mean
1 Annual Expenditures (000 USD)																
a. Capital Expenditures	26,986	23,912	15,103	13,735	18,094	23,540	32,923	27,652	38,623	36,435	37,117	48,956	54,461	59,502	724,723	24,157
b. Non Capital & operating expenditures	93,983	83,277	52,597	47,835	63,017	81,984	114,661	96,303	134,512	126,891	129,267	170,498	189,670	207,224	2,523,970	84,132
c. Total Expenditures	120,969	107,189	67,700	61,570	81,111	105,524	147,584	123,955	173,135	163,326	166,384	219,454	244,131	266,726	3,248,693	108,290
2 Lifting																
a. Oil (000 BL)	16,400	16,409	14,770	14,397	15,559	17,473	18,786	18,741	18,210	25,281	24,607	23,661	26,516	21,401	514,174	19,776
c. Oil Prices (USD/B)	27.64	13.94	18.20	17.90	18.06	23.23	20.19	20.03	17.73	16.61	17.58	20.93	19.81	12.63	19.88	19.88
d. Gas (000 CFT)	12,117	13,336	23,473	35,344	23,699	36,220	41,006	46,314	45,421	55,201	53,993	48,163	63,888	53,360	592,882	28,232
e. Gas Price(USD/CFT)	2.54	1.96	1.17	1.08	1.84	2.36	2.20	2.02	2.04	2.35	2.31	3.62	2.95	2.62	2.26	2.26
f Prod oil& gas (000BOE)	19,034	19,308	19,873	22,080	20,711	25,347	27,700	28,809	28,084	37,281	36,345	34,131	40,405	33,001	643,061	24,733
g Prod oil &gas (000BOE)	2,634	2,899	5,103	7,683	5,152	7,874	8,914	10,068	9,874	12,000	11,738	10,470	13,889	11,600	128,887	4,957
h Cum Oil & gas (000 BOE)	269,986	289,294	309,167	331,247	351,958	377,305	405,005	433,815	461,899	499,180	535,524	569,656	610,060	643,061	643,061	
3 Gross Revenue before FTP																
a Gross Revenues oil	453,305	228,798	268,831	257,736	281,015	405,858	379,293	375,396	322,896	419,858	432,543	495,184	525,365	270,396	9,953,538	382,828
b Gross Revenues gas	30,790	26,116	27,463	38,297	43,693	85,376	90,198	93,677	92,677	129,607	124,767	174,514	188,592	139,892	1,385,264	65,965
c Gross Revenues oil&gas (000 USD)	484,095	254,914	296,294	296,033	324,708	491,234	469,491	469,073	415,573	549,465	557,310	669,698	713,957	410,288	11,338,802	436,108
4 FTP																
a FTP oil	45,331	22,880	26,883	25,774	28,102	40,586	37,929	37,540	32,290	41,986	43,254	49,518	52,537	27,040	995,354	38,283
b FTP gas	3,079	2,612	2,746	3,830	4,369	8,538	9,020	9,368	9,268	12,961	12,477	17,451	18,859	13,989	138,526	6,596
c FTP oil & gas	48,410	25,491	29,629	29,603	32,471	49,123	46,949	46,907	41,557	54,947	55,731	66,970	71,396	41,029	1,133,880	43,611
5 Gross Revenue after FTP																
a Gross Revenue oil after FTP	407,975	205,918	241,948	231,962	252,914	365,272	341,364	337,856	290,606	377,872	389,289	445,666	472,829	243,356	8,958,184	344,546
b Gross Revenue gas after FTP	27,711	23,504	24,717	34,467	39,324	76,838	81,178	84,309	83,409	116,646	112,290	157,063	169,733	125,903	1,246,738	59,368
c Gross Revenue oil & gas after FTP	435,686	229,423	266,665	266,430	292,237	442,111	422,542	422,166	374,016	494,519	501,579	602,728	642,561	369,259	10,204,922	392,497
6 Cost Recovery oil & gas																
a. Unrecovered cost:	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
b. Current Year Operating Cost	93,983	83,277	52,597	47,835	63,017	81,984	114,661	96,303	134,512	126,891	129,267	170,498	189,670	207,224	2,523,970	84,132
c. Current Depreciation	26,601	27,544	23,873	22,615	20,283	20,368	21,416	22,651	27,678	31,160	34,875	37,145	44,077	155,073	724,723	24,157
d. Total Cost Recovery	120,584	110,821	76,470	70,450	83,300	102,352	136,077	118,954	162,190	158,051	164,142	207,643	233,747	362,297	3,397,806	113,260
e. Current Investment Credit	4,258	3,773	2,383	2,167	2,855	3,715	5,195	4,363	6,095	5,749	5,857	7,725	8,594	9,389	114,361	3,812
f. Total Recoverable	124,842	114,594	78,853	72,617	86,155	106,066	141,272	123,317	168,285	163,801	169,999	215,368	242,341	371,687	3,512,168	117,072
g. Current Maximum cost recovery	435,686	229,423	266,665	266,430	292,237	442,111	422,542	422,166	374,016	494,519	501,579	602,728	642,561	369,259	10,204,922	340,164
h. Actual cost recoverable	124,842	114,594	78,853	72,617	86,155	106,066	141,272	123,317	168,285	163,801	169,999	215,368	242,341	369,259	3,360,627	112,021

Appendix B5

Case C2 base case: Cash flow simulation of large oil and gas field using IP5 figures

000USD

	%	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
7 Equity to be split																	
a Equity to be split oil & gas		0	0	0	0	0	33,695	63,322	220,499	287,132	312,765	386,453	600,025	520,821	378,797	230,841	224,796
b Equity to be split oil & gas		0	0	0	0	0	33,695	63,322	220,499	287,132	308,728	377,249	560,627	480,942	352,118	213,137	185,564
c Equity to be split gas							0	0	0	0	4,037	9,204	39,398	39,879	26,679	17,704	39,232
8 GOI Share																	
a. GOI Equity share oil	64.28%	0	0	0	0	0	21,661	40,707	141,749	184,585	198,468	242,517	360,403	309,177	226,362	137,017	119,291
b. GOI Equity share gas	37.5%		0	0	0	0	0	0	0	0	1,514	3,451	14,774	14,955	10,005	6,639	14,712
c GOI share from FTP oil	100%	0	0	0	0	5,405	22,209	24,563	35,065	40,564	39,667	47,935	72,061	66,798	54,481	37,258	37,700
d. GOI share from FTP gas	100%	0	0	0	0	0	0	0	0	0	260	661	1,900	1,709	1,197	1,337	2,897
e. Domestic Requirement						0	0	0	0	0	30,104	36,380	54,689	50,695	41,347	28,276	28,611
f. Gov.Tax Entitlement	44%					0	7,174	12,608	36,100	46,143	36,883	46,398	75,849	65,781	46,493	27,772	29,585
g Total GOI Share		0	0	0	0	5,405	51,045	77,878	212,914	271,292	306,897	377,343	579,676	509,114	379,884	238,299	232,796
9 Contractor Share																	
a. Contractor Equity Share oil	35.71%	0	0	0	0	0	12,034	22,615	78,750	102,547	110,260	134,732	200,224	171,765	125,757	76,121	66,273
b. Contractor Equity Share gas	62.5%	0	0	0	0	0	0	0	0	0	2,523	5,752	24,624	24,924	16,674	11,065	24,520
c Contractor Share from FTP oil	0%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
d. Contractor Share from FTP gas	0%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
e. DMO oil first 5 prod.year	25%	0	0	0	0	0	0	0	0	0	30,104	36,380	54,689	50,695	41,347	28,276	28,611
after 5 prod-years	15%																
f. Taxable Share		0	0	0	0	0	16,305	28,654	82,046	104,871	83,826	105,450	172,383	149,502	105,665	63,118	67,239
g Gov.Tax Entitlement	44%	0	0	0	0	0	7,174	12,608	36,100	46,143	36,883	46,398	75,849	65,781	46,493	27,772	29,585
h Net Profit Contractor		0	0	0	0	0	4,860	10,007	42,649	56,404	45,795	57,707	94,310	80,214	54,591	31,137	32,597
1 Total Contractor Share		0	0	0	0	48,646	171,047	167,756	137,735	134,346	92,374	108,624	159,933	175,953	176,896	147,648	173,168
10 Party's Take																	
a % GOI Take						10%	23%	32%	61%	67%	77%	78%	78%	74%	68%	62%	57%
b % Contractor Take						90%	77%	68%	39%	33%	23%	22%	22%	26%	32%	38%	43%
11 Contractor Cash analysis																	
a. Net Cash flow Contractor		(885)	(6,841)	(23,697)	(48,579)	8,240	49,723	(3,806)	44,094	68,335	59,790	70,404	96,746	76,319	46,746	28,097	29,505
b. NPV @15%		(770)	(5,942)	(21,524)	(49,299)	(45,202)	(23,705)	(25,136)	(10,722)	8,703	23,483	38,615	56,698	69,102	75,708	79,161	82,314
c NPV @15% /B						(3.40)	(0.75)	(0.48)	(0.13)	0.08	0.17	0.24	0.31	0.34	0.34	0.34	0.33
d. IRR									7%	20%	26%	30%	33%	34%	35%	35%	35%
e. POT									7								

Appendix B5

Case C2 base case: Cash flow simulation of large oil and gas field using IP5 figures

000USD

	17	18	19	20	21	22	23	24	25	26	27	28	29	30	Total	Mean
7 Equity to be split																
a Equity to be split oil & gas	310,843	114,828	187,811	193,813	206,082	336,044	281,270	298,849	205,731	330,718	331,580	387,360	400,220	0	6,844,295	228,143
b Equity to be split oil & gas	267,826	97,587	139,586	126,371	154,818	231,654	190,753	194,407	133,398	224,265	224,495	268,532	262,648	0	5,599,354	186,645
c Equity to be split gas	43,018	17,242	48,225	67,442	51,264	104,391	90,516	104,442	72,333	106,453	107,085	118,828	137,571	0	1,244,941	49,798
8 GOI Share																
a. GOI Equity share oil	172,174	62,734	89,734	81,238	99,526	148,920	122,627	124,976	85,756	144,170	144,318	172,628	168,845	0	3,599,584	119,986
b. GOI Equity share gas	16,132	6,466	18,084	25,291	19,224	39,147	33,944	39,166	27,125	39,920	40,157	44,560	51,589	0	466,853	
c GOI share from FTP oil	45,331	22,880	26,883	25,774	28,102	40,586	37,929	37,540	32,290	41,986	43,254	49,518	52,537	27,040	995,354	33,178
d. GOI share from FTP gas	3,079	2,612	2,746	3,830	4,369	8,538	9,020	9,368	9,268	12,961	12,477	17,451	18,859	13,989	138,526	
e. Domestic Requirement	34,403	17,364	20,402	19,560	21,327	30,802	28,786	28,490	24,506	31,864	32,827	37,581	39,871	20,521	658,407	25,323
f. Gov.Tax Entitlement	40,653	14,097	27,268	30,752	30,299	53,192	44,488	48,656	32,753	53,026	52,859	61,739	65,343	0	985,911	37,920
g Total GOI Share	311,771	126,152	185,119	186,445	202,846	321,184	276,793	288,194	211,697	323,927	325,892	383,478	397,045	61,550	6,844,634	228,154
9 Contractor Share																
a. Contractor Equity Share oil	95,652	34,852	49,852	45,132	55,292	82,733	68,126	69,431	47,642	80,095	80,177	95,904	93,803	0	1,999,770	66,659
b. Contractor Equity Share gas	26,886	10,776	30,141	42,151	32,040	65,244	56,573	65,276	45,208	66,533	66,928	74,267	85,982	0		
c Contractor Share from FTP oil	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
d. Contractor Share from FTP gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
e. DMO oil first 5 prod.year	34,403	17,364	20,402	19,560	21,327	30,802	28,786	28,490	24,506	31,864	32,827	37,581	39,871	20,521	658,407	21,947
after 5 prod-years																
f. Taxable Share	92,394	32,038	61,974	69,891	68,860	120,891	101,109	110,581	74,440	120,513	120,135	140,316	148,508	0	2,240,706	74,690
g Gov.Tax Entitlement	40,653	14,097	27,268	30,752	30,299	53,192	44,488	48,656	32,753	53,026	52,859	61,739	65,343	0	985,911	32,864
h Net Profit Contractor	47,482	14,168	32,322	36,971	35,707	63,984	51,426	57,562	35,591	61,738	61,418	70,852	74,570	(20,521)	1,133,541	37,785
1 Total Contractor Share	172,324	128,762	111,175	109,588	121,862	170,050	192,698	180,879	203,876	225,538	231,418	286,220	316,912	348,738	4,494,168	149,806
10 Party's Take																
a % GOI Take	64%	49%	62%	63%	62%	65%	59%	61%	51%	59%	58%	57%	56%	15%	60%	57%
b % Contractor Take	36%	51%	38%	37%	38%	35%	41%	39%	49%	41%	42%	43%	44%	85%	40%	43%
11 Contractor Cash analysis																
a. Net Cash flow Contractor	51,355	21,573	43,475	48,018	40,751	64,526	45,114	56,924	30,741	62,212	65,034	66,766	72,781	82,012	1,245,475	41,516
b. NPV @15%	87,087	88,830	91,885	94,819	96,984	99,965	101,777	103,766	104,700	106,343	107,837	109,171	110,435	111,673	111,673	
c NPV @15% /B	0.32	0.31	0.30	0.29	0.28	0.26	0.25	0.24	0.23	0.21	0.20	0.19	0.18	0.17	0.17	
d. IRR	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	
e. POT															7	

Appendix B6

Case C3 base case: Cash flow simulation of very large oil and gas field using IP5 figures

000USD

	%	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
1 Annual Expenditures (000 USD)																	
a. Capital Expenditures	22.3%	1,722	2,042	2,029	5,224	15,062	28,951	23,414	17,404	13,351	27,779	38,154	39,047	32,836	42,430	48,999	46,060
b. Non Capital & operating expenditures		5,997	7,111	7,065	18,194	52,454	100,828	81,542	60,613	46,495	96,744	132,879	135,988	114,359	147,768	170,649	160,414
c. Total Expenditures		7,719	9,153	9,094	23,418	67,516	129,779	104,956	78,017	59,846	124,523	171,033	175,035	147,195	190,198	219,648	206,474
2 Lifting																	
a. Oil (000 BL)					414	3,423	14,362	41,897	40,276	38,664	36,275	37,558	30,719	31,914	32,628	30,470	28,343
c. Oil Prices (USD/B)					12.18	12.07	12.26	13.27	13.51	18.83	31.03	21.03	20.44	30.23	29.60	28.43	14.26
d. Gas (000 CFT)									2,248	1,538	1,940	1,876	1,973	6,263	23,529	24,831	28,445
e. Gas Price(USD/CFT)									1.20	2.23	4.50	4.96	5.13	3.60	3.31	3.80	2.46
f Prod oil& gas (000BOE)					414	3,423	14,362	41,897	40,765	38,998	36,697	37,966	31,148	33,276	37,743	35,868	34,527
g Prod gas (000BOE)						0	0	0	489	334	422	408	429	1,362	5,115	5,398	6,184
Oil&gas/day					1	9	39	115	112	107	101	104	85	91	103	98	95
3 Gross Revenue before FTP																	
a Gross Revenues oil					5,044	41,310	176,102	555,770	544,062	728,111	1,125,759	789,968	627,851	964,692	965,941	866,192	404,042
b Gross Revenues gas									2,697	3,425	8,726	9,308	10,129	22,551	77,928	94,458	70,010
c Gross Revenues oil&gas (000 USD)					5,044	41,310	176,102	555,770	546,759	731,536	1,134,485	799,276	637,980	987,243	1,043,869	960,650	474,052
4 FTP																	
a FTP oil	10%				504	4,131	17,610	55,577	54,406	72,811	112,576	78,997	62,785	96,469	96,594	86,619	40,404
b FTP gas									270	343	873	931	1,013	2,255	7,793	9,446	7,001
c FTP oil & gas					504	4,131	17,610	55,577	54,676	73,154	113,449	79,928	63,798	98,724	104,387	96,065	47,405
5 Gross Revenue after FTP																	
a Gross Revenue oil after FTP					4,540	37,179	158,492	500,193	489,656	655,300	1,013,183	710,971	565,066	868,223	869,347	779,573	363,638
b Gross Revenue gas after FTP									2,427	3,083	7,853	8,377	9,116	20,296	70,135	85,012	63,009
c Gross Revenue oil & gas after FTP					4,540	37,179	158,492	500,193	492,083	658,382	1,021,037	719,348	574,182	888,519	939,482	864,585	426,647
6 Cost Recovery oil & gas																	
a. Unrecovered cost:		0	(5,997)	(13,108)	(20,173)	(38,320)	(61,804)	(20,319)	0	0	0	0	0	0	0	0	0
b. Current Year Operating Cost		5,997	7,111	7,065	18,194	52,454	100,828	81,542	60,613	46,495	96,744	132,879	135,988	114,359	147,768	170,649	160,414
c. Current Depreciation	5ys DDBL	0	0	0	2,754	5,831	11,611	14,562	17,886	17,713	23,525	25,868	27,737	28,050	35,069	41,014	42,487
d. Total Cost Recovery		5,997	13,108	20,173	41,122	96,606	174,242	116,423	78,499	64,208	120,270	158,747	163,724	142,408	182,837	211,662	202,900
e. Current Investment Credit	15.78%	0	0	0	1,738	2,377	4,569	3,695	2,746	2,107	4,383	6,021	6,162	5,182	6,695	7,732	7,268
f. Total Recoverable		5,997	13,108	20,173	42,860	98,983	178,811	120,117	81,246	66,315	124,653	164,768	169,886	147,590	189,533	219,394	210,169
g. Current Maximum cost recovery		0	0	0	4,540	37,179	158,492	500,193	492,083	658,382	1,021,037	719,348	574,182	888,519	939,482	864,585	426,647
h. Actual cost recoverable:		0	0	0	4,540	37,179	158,492	120,117	81,246	66,315	124,653	164,768	169,886	147,590	189,533	219,394	210,169

Appendix B6

Case C3 base case: Cash flow simulation of very large oil and gas field using IP5 figures

000USD

	17	18	19	20	21	22	23	24	25	26	27	28	29	30	Total	Mean
1 Annual Expenditures (000 USD)																
a. Capital Expenditures	26,585	22,638	28,203	25,244	28,564	51,327	36,148	31,599	34,633	60,623	69,218	80,119	83,298	42,987	1,005,688	33,523
b. Non Capital & operating expenditures	92,585	78,840	98,221	87,915	99,477	178,753	125,891	110,050	120,615	211,129	241,063	279,028	290,098	149,711	3,502,478	116,749
c. Total Expenditures	119,170	101,478	126,424	113,159	128,041	230,080	162,039	141,649	155,248	271,752	310,281	359,147	373,396	192,698	4,508,166	150,272
2 Lifting																
a. Oil (000 BL)	25,576	18,396	17,236	14,947	14,695	13,913	12,961	14,051	12,389	12,312	13,681	15,174	15,234	16,443	583,951	21,628
c. Oil Prices (USD/B)	17.58	17.19	17.65	22.50	19.99	19.34	17.79	16.06	17.23	17.31	19.40	13.14	16.61	28.57	19.17	19.17
d. Gas (000 CFT)	38,473	41,200	42,779	70,636	88,644	96,925	106,634	129,841	127,951	154,126	185,362	239,784	260,883	467,165	2,143,046	93,176
e. Gas Price(USD/CFT)	1.85	1.83	1.91	2.38	2.49	2.56	2.14	2.05	2.33	3.31	3.15	1.99	2.80	3.34	2.84	2.84
f Prod oil& gas (000BOE)	33,940	27,353	26,536	30,303	33,965	34,984	36,142	42,277	40,204	45,818	53,977	67,301	71,948	118,001	1,049,831	38,883
g Prod gas (000BOE)	8,364	8,957	9,300	15,356	19,270	21,071	23,181	28,226	27,815	33,506	40,296	52,127	56,714	101,558	465,880	17,918
Oil&gas/day	93	75	73	83	93	96	99	116	110	126	148	184	197	323	107	107
3 Gross Revenue before FTP																
a Gross Revenues oil	449,686	316,190	304,221	336,369	293,818	269,056	230,541	225,679	213,473	213,104	265,407	199,440	252,990	469,765	11,834,583	438,318
b Gross Revenues gas	71,005	75,432	81,920	168,279	220,843	248,292	228,670	266,403	297,976	510,208	584,747	476,772	731,181	1,558,490	5,819,450	253,020
c Gross Revenues oil&gas (000 USD)	520,691	391,622	386,141	504,648	514,661	517,348	459,211	492,082	511,449	723,312	850,154	676,212	984,171	2,028,255	17,654,033	653,853
4 FTP																
a FTP oil	44,969	31,619	30,422	33,637	29,382	26,906	23,054	22,568	21,347	21,310	26,541	19,944	25,299	46,977	1,183,458	43,832
b FTP gas	7,101	7,543	8,192	16,828	22,084	24,829	22,867	26,640	29,798	51,021	58,475	47,677	73,118	155,849	581,945	25,302
c FTP oil & gas	52,069	39,162	38,614	50,465	51,466	51,735	45,921	49,208	51,145	72,331	85,015	67,621	98,417	202,826	1,765,403	65,385
5 Gross Revenue after FTP																
a Gross Revenue oil after FTP	404,717	284,571	273,799	302,732	264,436	242,150	207,487	203,111	192,126	191,794	238,866	179,496	227,691	422,789	10,651,125	394,486
b Gross Revenue gas after FTP	63,905	67,889	73,728	151,451	198,759	223,463	205,803	239,763	268,178	459,187	526,272	429,095	658,063	1,402,641	5,237,505	227,718
c Gross Revenue oil & gas after FTP	468,622	352,460	347,527	454,183	463,195	465,613	413,290	442,874	460,304	650,981	765,139	608,591	885,754	1,825,430	15,888,630	588,468
6 Cost Recovery oil & gas																
a. Unrecovered cost:	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
b. Current Year Operating Cost	92,585	78,840	98,221	87,915	99,477	178,753	125,891	110,050	120,615	211,129	241,063	279,028	290,098	149,711	3,502,478	116,749
c. Current Depreciation	37,038	35,714	35,396	32,160	26,639	31,875	34,263	32,895	34,118	46,146	48,312	55,183	62,932	198,912	1,005,688	33,523
d. Total Cost Recovery	129,623	114,554	133,617	120,075	126,116	210,628	160,154	142,944	154,733	257,275	289,375	334,211	353,031	348,622	4,667,887	155,596
e. Current Investment Credit	4,195	3,572	4,450	3,983	4,507	8,099	5,704	4,986	5,465	9,566	10,923	12,643	13,144	6,783	158,698	5,290
f. Total Recoverable	133,818	118,127	138,067	124,059	130,624	218,727	165,859	147,931	160,198	266,841	300,297	346,854	366,175	355,406	4,826,585	160,886
g. Current Maximum cost recovery	468,622	352,460	347,527	454,183	463,195	465,613	413,290	442,874	460,304	650,981	765,139	608,591	885,754	1,825,430	15,888,630	529,621
h. Actual cost recoverable:	133,818	118,127	138,067	124,059	130,624	218,727	165,859	147,931	160,198	266,841	300,297	346,854	366,175	355,406	4,666,864	155,562

Appendix B6

Case C3 base case: Cash flow simulation of very large oil and gas field using IP5 figures

000USD

	%	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
7 Equity to be split																	
a Equity to be split oil & gas		0	0	0	0	0	0	380,076	410,838	592,067	896,384	554,581	404,296	740,929	749,950	645,191	216,478
b Equity to be split oil		0	0	0	0	0	0	380,076	405,912	586,991	886,082	548,623	398,729	710,613	648,315	548,091	177,707
c Equity to be split gas							0	0	4,925	5,076	10,302	5,957	5,567	30,316	101,635	97,099	38,771
8 GOI Share																	
a. GOI Equity share oil	64.28%	0	0	0	0	0	0	244,334	260,944	377,352	569,624	352,686	256,326	456,822	416,774	352,344	114,240
b. GOI Equity share gas	37.5%	0	0	0	0	0	0	0	1,847	1,904	3,863	2,234	2,088	11,369	38,113	36,412	14,539
c GOI share from FTP oil	100%	0	0	0	504	4,131	17,610	55,577	54,406	72,811	112,576	78,997	62,785	96,469	96,594	86,619	40,404
d. GOI share from FTP gas	100%	0	0	0	0	0	0	0	270	343	873	931	1,013	2,255	7,793	9,446	7,001
e. Domestic Requirement						0	0	0	0	55,258	85,437	59,953	47,649	73,213	73,308	65,738	30,664
f. Gov.Tax Entitlement	44%					0	0	61,352	66,349	70,251	106,411	64,120	45,934	90,071	100,518	87,308	28,293
g Total GOI Share		0	0	0	504	4,131	17,610	361,263	383,816	577,918	878,783	558,921	415,794	730,199	733,100	637,868	235,142
9 Contractor Share																	
a. Contractor Equity Share oil	35.71%	0	0	0	0	0	0	135,741	144,969	209,640	316,458	195,937	142,403	253,790	231,541	195,747	63,467
b. Contractor Equity Share gas	62.5%	0	0	0	0	0	0	0	3,078	3,173	6,439	3,723	3,480	18,948	63,522	60,687	24,232
c Contractor Share from FTP oil	0%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
d. Contractor Share from FTP gas	0%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
e. DMO oil first 5 prod.year	25%	0	0	0	0	0	0	0	0	55,258	85,437	59,953	47,649	73,213	73,308	65,738	30,664
f. Taxable Share		0	0	0	0	0	0	139,436	150,793	159,661	241,843	145,728	104,395	204,706	228,450	198,428	64,303
g Gov.Tax Entitlement	44%	0	0	0	0	0	0	61,352	66,349	70,251	106,411	64,120	45,934	90,071	100,518	87,308	28,293
h Net Profit Contractor		0	0	0	0	0	0	74,389	81,698	87,303	131,049	75,587	52,300	109,454	121,237	103,388	28,741
1 Total Contractor Share		0	0	0	4,540	37,179	158,492	194,507	162,943	153,618	255,702	240,355	222,186	257,044	310,769	322,782	238,910
9 Party's Take																	
a % GOI Take					10%	10%	10%	65%	70%	79%	77%	70%	65%	74%	70%	66%	50%
b % Contractor Take					90%	90%	90%	35%	30%	21%	23%	30%	35%	26%	30%	34%	50%
10 Contractor Cash analysis																	
a. Net Cash flow Contractor		(7,719)	(9,153)	(9,094)	(18,878)	(30,337)	28,713	89,551	84,926	93,772	131,179	69,322	47,151	109,849	120,571	103,134	32,436
b. NPV @15%		(6,712)	(13,633)	(19,613)	(30,406)	(45,489)	(33,076)	590	28,352	55,008	87,433	102,334	111,146	129,000	146,040	158,715	162,181
c NPV @15% /B					(73.45)	(11.86)	(1.82)	0.01	0.28	0.39	0.50	0.48	0.45	0.46	0.46	0.45	0.42
d. IRR							#NUM!	15%	30%	38%	43%	45%	46%	47%	48%	48%	48%
e. POT								6									

Appendix B6

Case C3 base case: Cash flow simulation of very large oil and gas field using IP5 figures

000USD

	17	18	19	20	21	22	23	24	25	26	27	28	29	30	Total	Mean
7 Equity to be split																
a Equity to be split oil & gas	334,804	234,333	209,459	330,124	332,571	246,886	247,431	294,943	300,106	384,140	464,841	261,737	519,579	1,470,024	11,221,766	374,059
b Equity to be split oil	252,299	157,601	136,052	162,836	143,885	98,187	88,731	98,025	92,478	103,225	117,818	59,012	110,014	204,843	7,116,146	237,205
c Equity to be split gas	82,505	76,732	73,408	167,288	188,686	148,699	158,700	196,918	207,628	280,915	347,023	202,724	409,565	1,265,181	4,105,620	164,225
8 GOI Share																
a. GOI Equity share oil	162,192	101,315	87,462	104,680	92,498	63,120	57,042	63,016	59,450	66,359	75,740	37,937	70,723	131,685	4,574,665	152,489
b. GOI Equity share gas	30,939	28,774	27,528	62,733	70,757	55,762	59,512	73,844	77,861	105,343	130,134	76,022	153,587	474,443	1,539,607	51,320
c GOI share from FTP oil	44,969	31,619	30,422	33,637	29,382	26,906	23,054	22,568	21,347	21,310	26,541	19,944	25,299	46,977	1,183,458	39,449
d. GOI share from FTP gas	7,101	7,543	8,192	16,828	22,084	24,829	22,867	26,640	29,798	51,021	58,475	47,677	73,118	155,849	581,945	19,398
e. Domestic Requirement	34,128	23,997	23,088	25,528	22,299	20,419	17,496	17,127	16,201	16,173	20,143	15,136	19,200	35,652	797,808	30,685
f. Gov.Tax Entitlement	49,165	36,880	33,366	62,113	66,671	50,901	52,397	64,214	66,906	90,566	109,889	63,925	127,254	367,412	1,962,268	75,472
g Total GOI Share	328,494	230,129	210,058	305,519	303,691	241,937	232,369	267,410	271,563	350,772	420,921	260,641	469,181	1,212,017	10,639,752	354,658
9 Contractor Share																
a. Contractor Equity Share oil	90,107	56,286	48,590	58,156	51,388	35,067	31,690	35,009	33,028	36,866	42,078	21,076	39,291	73,158	2,541,482	84,716
b. Contractor Equity Share gas	51,566	47,957	45,880	104,555	117,929	92,937	99,187	123,074	129,768	175,572	216,889	126,703	255,978	790,738	2,566,012	85,534
c Contractor Share from FTP oil	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
d. Contractor Share from FTP gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
e. DMO oil first 5 prod.year	34,128	23,997	23,088	25,528	22,299	20,419	17,496	17,127	16,201	16,173	20,143	15,136	19,200	35,652	797,808	26,594
f. Taxable Share	111,740	83,819	75,832	141,166	151,525	115,684	119,085	145,942	152,059	205,831	249,747	145,285	289,213	835,028	4,459,700	148,657
g Gov.Tax Entitlement	49,165	36,880	33,366	62,113	66,671	50,901	52,397	64,214	66,906	90,566	109,889	63,925	127,254	367,412	1,962,268	65,409
h Net Profit Contractor	58,379	43,367	38,015	75,070	80,347	56,683	60,983	76,741	79,688	105,699	128,936	68,717	148,815	460,832	2,347,418	78,247
1 Total Contractor Share	192,197	161,493	176,083	199,129	210,970	275,411	226,842	224,672	239,886	372,540	429,233	415,571	514,990	816,238	7,014,281	233,809
9 Party's Take																
a % GOI Take	63%	59%	54%	61%	59%	47%	51%	54%	53%	48%	50%	39%	48%	60%	60%	54%
b % Contractor Take	37%	41%	46%	39%	41%	53%	49%	46%	47%	52%	50%	61%	52%	40%	40%	46%
10 Contractor Cash analysis																
a. Net Cash flow Contractor	73,027	60,015	49,659	85,970	82,929	45,331	64,803	83,023	84,638	100,788	118,952	56,424	141,594	623,540	2,506,115	83,537
b. NPV @15%	168,967	173,817	177,306	182,559	186,965	189,059	191,663	194,563	197,134	199,796	202,529	203,656	206,115	215,532	215,532	
c NPV @15% /B	0.40	0.39	0.37	0.36	0.35	0.33	0.31	0.30	0.28	0.27	0.26	0.24	0.22	0.21	0.21	
d. IRR	48%	48%	48%	48%	48%	48%	48%	48%	48%	48%	48%	48%	48%	48%	48%	
e. POT															6	

Appendix B7

Case C4 base case: Cash flow simulation of extra large oil and gas field using IP5 figures

000USD

	%	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
1 Annual Expenditures (000 USD)																	
a. Capital Expenditures	22.3%	76	370	625	1,191	2,482	4,984	6,075	16,523	31,880	29,608	41,857	30,191	40,228	60,482	67,814	43,160
b. Non Capital & operating expenditures		264	1,288	2,175	4,149	8,642	17,358	21,156	57,546	111,027	103,113	145,773	105,144	140,103	210,641	236,174	150,314
c. Total Expenditures		340	1,658	2,800	5,340	11,124	22,342	27,231	74,069	142,907	132,721	187,630	135,335	180,331	271,123	303,988	193,474
2 Lifting																	
a. Oil (000 BL)											1,985	9,581	20,789	22,454	27,037	27,717	29,203
c. Oil Prices (USD/B)											7.50	14.91	20.39	33.98	37.23	35.85	32.29
d. Gas (000 CFT)													141,541	203,380	210,786	215,545	241,459
e. Gas Price(USD/CFT)													1.60	4.19	4.77	5.01	4.48
f Prod oil& gas (000BOE)											1,985	9,581	51,559	66,667	72,860	74,575	81,694
g Prod gas (000BOE)													30,770	44,213	45,823	46,858	52,491
h. Oil&gas (000 BOEPD)											5.438	26.249	141.257	182.649	199.617	204.314	223.819
3 Gross Revenue before FTP																	
a Gross Revenues oil (000 USD)											14,891	142,886	423,990	763,054	1,006,666	993,782	942,835
b Gross Revenues gas (000 USD)											0	0	227,120	852,525	1,005,412	1,079,188	1,080,977
c Gross Revenues oil&gas (000 USD)											14,891	142,886	651,110	1,615,579	2,012,078	2,072,970	2,023,812
4 FTP																	
a FTP oil	10%										1,489	14,289	42,399	76,305	100,667	99,378	94,284
b FTP gas											0	0	22,712	85,253	100,541	107,919	108,098
c FTP oil & gas											1,489	14,289	65,111	161,558	201,208	207,297	202,381
5 Gross Revenue after FTP																	
a Gross Revenue oil after FTP											13,402	128,597	381,591	686,749	905,999	894,404	848,552
b Gross Revenue gas after FTP											0	0	204,408	767,273	904,871	971,269	972,879
c Gross Revenue oil & gas after FTP											13,402	128,597	585,999	1,454,021	1,810,870	1,865,673	1,821,431
6 Cost Recovery oil & gas																	
a. Unrecovered cost:		0	(264)	(1,552)	(3,728)	(7,876)	(16,519)	(33,877)	(55,033)	(2,513)	(108,515)	(19,454)	(32,381)	0	0	0	0
b. Current Year Operating Cost		264	1,288	2,175	4,149	8,642	17,358	21,156	57,546	111,027	103,113	145,773	105,144	140,103	210,641	236,174	150,314
c. Current Depreciation	5ysDDBL	0	0	0	0	0	0	0	0	0	23,453	28,054	28,586	31,500	61,007	50,379	45,806
d. Total Cost Recovery		264	1,552	3,728	7,876	16,519	33,877	55,033	2,513	108,515	18,052	154,374	101,349	171,603	271,647	286,553	196,119
e. Current Investment Credit	15.78%	0	0	0	0	0	0	0	0	0	14,804	6,605	4,764	6,348	9,544	10,701	6,811
f. Total Recoverable		264	1,552	3,728	7,876	16,519	33,877	55,033	2,513	108,515	32,856	160,979	106,113	177,951	281,191	297,254	202,930
g. Current Maximum cost recovery		0	0	0	0	0	0	0	0	0	13,402	128,597	585,999	1,454,021	1,810,870	1,865,673	1,821,431
h. Actual cost recoverable:		0	0	0	0	0	0	0	0	0	13,402	128,597	106,113	177,951	281,191	297,254	202,930

Appendix B7

Case C4 base case: Cash flow simulation of extra large oil and gas field using IP5 figures

000USD

	17	18	19	20	21	22	23	24	25	26	27	28	29	30	Total	Mean
1 Annual Expenditures (000 USD)																
a. Capital Expenditures	36,420	37,792	43,663	35,049	32,684	37,169	43,710	56,201	61,155	65,812	84,982	45,656	32,437	34,379	1,024,655	34,155
b. Non Capital & operating expenditures	126,837	131,619	152,065	122,063	113,828	129,448	152,229	195,731	212,981	229,203	295,963	159,005	112,967	119,730	3,568,536	118,951
c. Total Expenditures	163,257	169,411	195,728	157,112	146,512	166,617	195,939	251,932	274,136	295,015	380,945	204,661	145,404	154,109	4,593,191	153,106
2 Lifting																
a. Oil (000 BL)	36,594	36,338	37,807	38,632	43,650	45,531	44,196	42,631	41,517	38,542	33,926	31,891	29,316	22,493	661,830	31,516
c. Oil Prices (USD/B)	28.91	27.94	13.38	18.09	15.07	17.92	22.41	19.92	19.84	17.80	16.35	17.32	20.20	19.48	21.75	21.75
d. Gas (000 CFT)	339,455	306,481	398,622	466,241	506,354	563,255	585,032	607,864	622,335	632,133	641,214	590,082	586,196	589,629	8,447,604	444,611
e. Gas Price(USD/CFT)	3.68	3.76	2.67	2.16	2.14	2.07	3.02	2.80	2.82	2.64	2.44	2.83	3.29	3.15	3.13	3.13
f Prod oil& gas (000BOE)	110,389	102,964	124,464	139,989	153,727	167,978	171,377	174,775	176,807	175,962	173,320	160,170	156,750	150,673	2,498,266	118,965
g Prod gas (000BOE)	73,795	66,626	86,657	101,357	110,077	122,447	127,181	132,144	135,290	137,420	139,394	128,279	127,434	128,180	1,836,436	96,655
h. Oil&gas (000 BOEPD)	302.434	282.094	340.997	383.531	421.170	460.213	469.526	478.837	484.403	482.088	474.850	438.821	429.452	412.803	325.932	325.932
3 Gross Revenue before FTP																
a Gross Revenues oil (000 USD)	1,057,935	1,015,119	505,675	698,905	657,969	816,018	990,388	849,032	823,751	685,969	554,701	552,397	592,163	438,094	14,526,220	691,725
b Gross Revenues gas (000 USD)	1,249,615	1,152,452	1,064,192	1,008,622	1,081,883	1,165,585	1,767,801	1,704,111	1,755,656	1,666,065	1,565,795	1,670,235	1,930,632	1,856,844	24,884,710	1,184,986
c Gross Revenues oil&gas (000 USD)	2,307,550	2,167,571	1,569,867	1,707,527	1,739,852	1,981,603	2,758,189	2,553,143	2,579,407	2,352,034	2,120,496	2,222,632	2,522,795	2,294,938	39,410,930	1,876,711
4 FTP																
a FTP oil	105,794	101,512	50,568	69,891	65,797	81,602	99,039	84,903	82,375	68,597	55,470	55,240	59,216	43,809	1,452,622	69,172
b FTP gas	124,962	115,245	106,419	100,862	108,188	116,559	176,780	170,411	175,566	166,607	156,580	167,024	193,063	185,684	2,488,471	118,499
c FTP oil & gas	230,755	216,757	156,987	170,753	173,985	198,160	275,819	255,314	257,941	235,203	212,050	222,263	252,280	229,494	3,941,093	187,671
5 Gross Revenue after FTP																
a Gross Revenue oil after FTP	952,142	913,607	455,108	629,015	592,172	734,416	891,349	764,129	741,376	617,372	499,231	497,157	532,947	394,285	13,073,598	622,552
b Gross Revenue gas after FTP	1,124,654	1,037,207	957,773	907,760	973,695	1,049,027	1,591,021	1,533,700	1,580,090	1,499,459	1,409,216	1,503,212	1,737,569	1,671,160	22,396,239	1,066,488
c Gross Revenue oil & gas after FTP	2,076,795	1,950,814	1,412,880	1,536,774	1,565,867	1,783,443	2,482,370	2,297,829	2,321,466	2,116,831	1,908,446	2,000,369	2,270,516	2,065,444	35,469,837	1,689,040
6 Cost Recovery oil & gas																
a. Unrecovered cost:	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
b. Current Year Operating Cost	126,837	131,619	152,065	122,063	113,828	129,448	152,229	195,731	212,981	229,203	295,963	159,005	112,967	119,730	3,568,536	118,951
c. Current Depreciation	45,841	48,636	49,132	39,761	36,392	36,912	40,005	42,010	46,235	52,193	61,943	60,835	54,911	141,065	1,024,655	34,155
d. Total Cost Recovery	172,679	180,255	201,197	161,824	150,220	166,360	192,234	237,740	259,216	281,396	357,906	219,840	167,878	260,795	4,439,112	147,970
e. Current Investment Credit	5,747	5,964	6,890	5,531	5,158	5,865	6,897	8,869	9,650	10,385	13,410	7,205	5,119	5,425	161,691	5,390
f. Total Recoverable	178,426	186,218	208,087	167,355	155,377	172,226	199,131	246,609	268,866	291,781	371,316	227,045	172,996	266,220	4,600,803	153,360
g. Current Maximum cost recovery	2,076,795	1,950,814	1,412,880	1,536,774	1,565,867	1,783,443	2,482,370	2,297,829	2,321,466	2,116,831	1,908,446	2,000,369	2,270,516	2,065,444	35,469,837	1,182,328
h. Actual cost recoverable:	178,426	186,218	208,087	167,355	155,377	172,226	199,131	246,609	268,866	291,781	371,316	227,045	172,996	266,220	4,319,091	143,970

Appendix B7

Case C4 base case: Cash flow simulation of extra large oil and gas field using IP5 figures

000USD

	%	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
a Equity to be split oil & gas		0	0	0	0	0	0	0	0	0	0	0	479,886	1,276,070	1,529,679	1,568,419	1,618,501
b Equity to be split oil & gas		0	0	0	0	0	0	0	0	0	0	0	193,495	429,791	567,635	582,931	578,562
c Equity to be split gas							0	0	0	0	0	0	286,391	846,280	962,044	985,488	1,039,939
8 GOI Share																	
a. GOI Equity share oil	64.29%	0	0	0	0	0	0	0	0	0	0	0	124,389	276,294	364,908	374,742	371,933
b. GOI Equity share gas	37.50%	0	0	0	0	0	0	0	0	0	0	0	107,397	317,355	360,766	369,558	389,977
c GOI share from FTP oil	100%	0	0	0	0	0	0	0	0	0	1,489	14,289	42,399	76,305	100,667	99,378	94,284
d. GOI share from FTP gas	100%	0	0	0	0	0	0	0	0	0	0	0	22,712	85,253	100,541	107,919	108,098
e. Domestic Requirement						0	0	0	0	0	0	0	0	0	0	75,421	71,554
f. Gov.Tax Entitlement	44%					0	0	0	0	0	0	0	111,260	303,059	357,961	334,136	348,413
g Total GOI Share		0	0	0	0	0	0	0	0	0	1,489	14,289	408,157	1,058,265	1,284,844	1,361,153	1,384,258
9 Contractor Share																	
a. Contractor Equity Share oil	35.71%	0	0	0	0	0	0	0	0	0	0	0	69,105	153,497	202,727	208,190	206,629
b. Contractor Equity Share gas	62.50%	0	0	0	0	0	0	0	0	0	0	0	178,995	528,925	601,277	615,930	649,962
c Contractor Share from FTP oil	0%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
d. Contractor Share from FTP gas	0%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
e. DMO oil first 5 prod.year	25%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	75,421	71,554
after 5 prod-years	15%																
f. Taxable Share		0	0	0	0	0	0	0	0	0	0	0	252,864	688,770	813,548	759,400	791,848
g Gov.Tax Entitlement	44%	0	0	0	0	0	0	0	0	0	0	0	111,260	303,059	357,961	334,136	348,413
h Net Profit Contractor		0	0	0	0	0	0	0	0	0	0	0	136,840	379,363	446,043	414,563	436,624
1 Total Contractor Share		0	0	0	0	0	0	0	0	0	13,402	128,597	242,953	557,314	727,234	711,817	639,554
10 Party's Take																	
a % GOI Take											10%	10%	63%	66%	64%	66%	68%
b % Contractor Take											90%	90%	37%	34%	36%	34%	32%
11 Contractor Cash analysis																	
a. Net Cash flow Contractor		(340)	(1,658)	(2,800)	(5,340)	(11,124)	(22,342)	(27,231)	(74,069)	(142,907)	(119,319)	(59,033)	107,618	376,983	456,111	407,829	446,080
b. NPV @15%		(296)	(1,549)	(3,390)	(6,444)	(11,974)	(21,633)	(31,870)	(56,084)	(96,707)	(126,201)	(138,889)	(118,775)	(57,504)	6,957	57,077	104,747
c NPV @15% /B											(63.58)	(12.01)	(1.88)	(0.44)	0.03	0.21	0.29
d. IRR													#DIV/0!	1%	16%	23%	27%
e. POT														12			

Appendix B7

Case C4 base case: Cash flow simulation of extra large oil and gas field using IP5 figures

000USD

	17	18	19	20	21	22	23	24	25	26	27	28	29	30	Total	Mean
a Equity to be split oil & gas	1,898,369	1,764,596	1,204,793	1,369,419	1,410,489	1,611,217	2,283,239	2,051,220	2,052,600	1,825,050	1,537,130	1,773,324	2,097,519	1,799,224	31,150,746	1,038,358
b Equity to be split oil & gas	629,313	622,758	365,966	377,912	400,501	436,726	588,819	500,331	481,981	399,751	300,880	353,082	392,286	268,594	8,471,317	282,377
c Equity to be split gas	1,269,057	1,141,837	838,827	991,508	1,009,988	1,174,491	1,694,420	1,550,889	1,570,619	1,425,299	1,236,250	1,420,242	1,705,233	1,530,630	22,679,428	907,177
8 GOI Share																
a. GOI Equity share oil	404,558	400,345	235,264	242,943	257,465	280,753	378,527	321,641	309,845	256,983	193,423	226,981	252,184	172,668	5,445,846	181,528
b. GOI Equity share gas	475,896	428,189	314,560	371,815	378,745	440,434	635,407	581,583	588,982	534,487	463,594	532,591	639,462	573,986	8,504,786	
c GOI share from FTP oil	105,794	101,512	50,568	69,891	65,797	81,602	99,039	84,903	82,375	68,597	55,470	55,240	59,216	43,809	1,452,622	48,421
d. GOI share from FTP gas	124,962	115,245	106,419	100,862	108,188	116,559	176,780	170,411	175,566	166,607	156,580	167,024	193,063	185,684	2,488,471	
e. Domestic Requirement	80,290	77,040	38,377	53,042	49,935	61,930	75,163	64,435	62,517	52,060	42,098	41,923	44,941	33,248	923,976	35,538
f. Gov.Tax Entitlement	415,084	380,594	274,332	311,146	320,980	366,945	528,457	480,668	484,399	436,438	374,627	430,775	513,062	450,889	7,223,225	277,816
g Total GOI Share	1,606,583	1,502,924	1,019,520	1,149,699	1,181,111	1,348,222	1,893,374	1,703,643	1,703,683	1,515,171	1,285,792	1,454,533	1,701,929	1,460,285	26,038,925	867,964
9 Contractor Share																
a. Contractor Equity Share oil	224,755	222,414	130,702	134,969	143,036	155,974	210,293	178,690	172,136	142,768	107,457	126,101	140,102	95,927	3,025,472	100,849
b. Contractor Equity Share gas	793,160	713,648	524,267	619,692	631,242	734,057	1,059,012	969,305	981,637	890,812	772,656	887,651	1,065,770	956,644		
c Contractor Share from FTP oil	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
d. Contractor Share from FTP gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
e. DMO oil first 5 prod.year	80,290	77,040	38,377	53,042	49,935	61,930	75,163	64,435	62,517	52,060	42,098	41,923	44,941	33,248	923,976	30,799
after 5 prod-years																
f. Taxable Share	943,372	864,985	623,482	707,150	729,501	833,966	1,201,039	1,092,428	1,100,906	991,905	851,426	979,034	1,166,050	1,024,747	16,416,421	547,214
g Gov.Tax Entitlement	415,084	380,594	274,332	311,146	320,980	366,945	528,457	480,668	484,399	436,438	374,627	430,775	513,062	450,889	7,223,225	240,774
h Net Profit Contractor	522,541	478,428	342,260	390,473	403,363	461,156	665,684	602,891	606,857	545,082	463,388	541,054	647,870	568,433	9,052,914	301,764
1 Total Contractor Share	700,967	664,647	550,347	557,828	558,741	633,381	864,815	849,500	875,724	836,863	834,704	768,099	820,866	834,653	13,372,005	445,734
10 Party's Take																
a % GOI Take	70%	69%	65%	67%	68%	68%	69%	67%	66%	64%	61%	65%	67%	64%	66%	61%
b % Contractor Take	30%	31%	35%	33%	32%	32%	31%	33%	34%	36%	39%	35%	33%	36%	34%	39%
11 Contractor Cash analysis																
a. Net Cash flow Contractor	537,710	495,236	354,619	400,716	412,229	466,764	668,876	597,568	601,588	541,848	453,759	563,438	675,462	680,544	8,778,814	292,627
b. NPV @15%	154,714	194,732	219,649	244,133	266,035	287,600	314,472	335,347	353,622	367,935	378,358	389,612	401,344	411,622	411,622	
c NPV @15% /B	0.33	0.34	0.32	0.29	0.27	0.25	0.24	0.22	0.21	0.20	0.19	0.18	0.17	0.16	0.16	
d. IRR	29%	31%	32%	33%	33%	33%	34%	34%	34%	34%	34%	34%	34%	35%	35%	
e. POT															12	